ORIGINAL

1999 Ten Year Site Plan

JEA

Building Community

April, 1999

Table of Contents

List of Tables

List of Figures

List of Abbreviations

Type of Generation Units

CC - Combined Cycle
CT, GT - Combustion Turbine
FS - Fossil Steam
IC - Internal Combustion

Status of Generation Units

M - Cold Storage, Reserve Shutdown
P - Planned
PR - Proposed
R - To Be Retired
RP - Repowered

Types Of Fuel

ALT - Alternate Fuel
C-Bit - Coal, Bituminous
C-Sub - Coal, Sub-bituminous
LO - #2 Fuel Oil (Distillate)
HO - 6 Fuel Oil
NG - Natural Gas
Pet Coke - Petroleum Coke

Fuel Transportation Methods

PL - Pipeline
RR - Railroad
TK - Truck
WA - Water

Executive Summary

This report documents the Ten Year Site Plan (TYSP) conducted for the JEA electric system. Analysis for the plan included a review of existing electric supply resources, forecasts of customer energy requirements and peak demands, forecasts of fuel prices and availability, and analysis of alternatives for resources to meet future capacity and energy needs, including full consideration of conservation and demand-side management alternatives.

JEA's existing supply system includes wholly-owned and jointly-owned generation, power purchases, and power sales. The total installed capacity based on JEA's ownership share is 2,593 MW summer and 2,716 MW winter, as of Janury 1, 1999. The existing supply system has a broad range of fuel diversity and generation technology.

Forecasts of system peak demand growth and energy consumption were utilized for the resource plan. A range of demand growth and energy consumption was reviewed, with the base case peak demand indicating a need for additional capacity to meet system reserve requirements beginning in the year 2000. This need encompasses the inclusion of existing supply resources, transmission system considerations, future changes in existing resources, and environmental and land use considerations.

The JEA currently employs demand-side management (DSM) to improve the efficiency of consumer electricity usage. The DSM effort includes three residential programs, one commercial/industrial program, and several education programs. These programs are designed to meet the conservation goals set forth by the Florida Public Service Commission (FPSC).

Eight self-build and two purchase power alternatives were modeled using EPRI's Electric Generation Expansion Analysis System (EGEAS), an optimal generation expansion model, to determine the least-cost expansion plan. The least-cost plan was based on the total present worth costs over a 30 year planning horizon. Several sensitivity analyses were performed to determine the impact on the least-cost plan.

In addition to cost considerations, environmental and land use considerations were factored into the resource plans. This ensured that the least-cost plans selected were socially and environmentally responsible and demonstrate the JEA's total commitment to the community.

Based on detailed modeling of the JEA system, forecast of demand and energy, forecast of fuel prices and availability, and environmental considerations; Table ES-1 presents the expansion plan that provides JEA with the least-cost plan which meets strategic goals. The expansion plan demonstrates strength with small variance in supply alternatives over the numerous sensitivities.

Table ES-1

Reference Plan

Year	Month/ Season	Expansion Plan
1999		
2000	Winter	Purchase 250 MW
	March	Shutdown Kennedy Unit 10
	May	Build 1-168 MW CT at Kennedy
	Summer	Purchase 125 MW
2001	January	Build 2-168 MW CTs at Brandy Branch
	October	Retire Southside Unit 4
	October	Retire Southside Unit 5
	December	Build 1-168 MW CT at Brandy Branch
2002	Winter	Purchase 25 MW
	April	Northside 1 CFB Repowering
	April	Northside 2 CFB Repowering
2003		
2004		
2005	June	Convert 2 Brandy Branch CTs to Combined Cycle (558 MW Unit; 186 Additional MWs)
2006		
2007	June	Build 1-168 MW CT
2008	Summer	Purchase 50 MW

1.0 Introduction

This report presents the 1999 Ten Year Site Plan for the JEA electrical supply system covering a 10 year planning period from 1999 to 2008.

1.1 Objective

The objective of this Ten Year Site Plan was to develop an environmentally sound power supply strategy for the JEA which provides reliable electric service at the lowest practical cost. The following specific objectives are identified to accomplish this broad objective.

- Develop a Basis for Decisions
- Determine the Future Resource Needs
- Evaluate the Demand-Side Options
- Evaluate the Supply-Side Options
- Evaluate the Economics
- Consider the Environmental and Land Use Impacts
- Document the Results and Conclusions

1.2 Summary of This Report

1.2.1 Basis for Decision

Section 2.0 of the Ten-Year Site Plan describes the basis on which all resource decisions were built throughout the study. These include economic measures, environmental goals, and reliability measures.

1.2.2 Future Resource Needs

Section 3.0 outlines the existing and the future resource needs of the JEA system. This section includes the base, high and low load and energy forecasts; the transmission system with details of the current system and proposed upgrades; changes to the existing generation system; and future resource needs.

1.2.3 Demand-Side Options

Section 4.0 summarizes the current demand-side resource options for the JEA. This section documents the goals set forth by the PSC, the current programs at the JEA, the program revisions, and the evaluation of residential direct load control.

1.2.4 Supply-Side Options

Section 5.0 summarizes the supply-side options evaluated for the Ten-Year Site Plan. The options considered included self-build options, purchased power, and advanced and renewable technologies.

1.2.5 Economic Evaluation

Section 6.0 describes the economic evaluation of the alternatives considered in the Ten-Year Site Plan. The least-cost plan, ranked by cumulative present worth costs over a thirty year period, is described in Table 6-1.

Numerous sensitivity analyses were performed for the Ten-Year Site Plan. The sensitivity analyses included low and high load and energy growth, low and high fuel price and escalation, high discount rate, and a self-build case where no purchases were allowed after 2000.

1.2.6 Environmental and Land Use Considerations

Section 7.0 analyzes the environmental and land use considerations of the Ten-Year Site Plan options. This section provides discussion and analyses of several key environmental factors including: water supply, land use, emissions, fuel storage, noise, and certification status.

1.2.7 Analysis Results and Conclusions

Section 8.0 summarizes the results of the economic analysis and provides conclusions and a recommended reference plan for the JEA system based on the results and issues of preceding sections.

1.2.8 Ten Year Site Plan Schedules

Section 9.0 presents the schedules required by the Florida Public Service Commission for the Ten Year Site Plan filing.

1.2.9 Appendices

The appendices document in greater detail the some of the assumptions and methodology used in the Ten-Year Site Plan. The appendices are included following the report.

2.0 Basis For Decisions

The following section establishes the basis for decisions made by the JEA in the integrated resource planning process. The three categories represent the major criteria for decisions made by the JEA.

2.1 Economic Measures

The fuel forecast, general escalation rate, and present worth discount rate represent three major categories of economic measures for decision making.

2.1.1 Fuel Forecast

The fuel forecast represents a major economic factor in the selection of resources for future supply to the JEA electrical system. The baseline fuel price forecast includes coal, natural gas, distillate oil, and petroleum coke. High and low fuel price projections are also developed for sensitivity analyses. JEA's delivered fuel cost projections for the base, low, and high cases are presented in Table 2-1. JEA currently purchases natural gas transportation from Florida Gas Transmission Company (FGT) under FTS-1. JEA's natural gas entitlements include 40,000 Mbtu/day for FGT FTS1 and contract extensions are at JEA's option.

2.1.2 General Inflation Rate

JEA uses a forecast of the Gross Domestic Product (GDP) Deflator as a base measure of general inflation to derive relative escalation rates for use in resource planning analyses. Based on Table 2-3, the average annual base escalation rate for the JEA system is forecast to be 2.3 percent.

2.1.3 Present Worth Discount Rate

The base case present worth discount rate applied in the study is consistent with the general escalation rate discussed above, 2.3 percent. A sensitivity of 5.0%, the current municipal bond rate, was also analyzed.

Table 2-1
Summary of Fuel Price Assumptions
(Base Case Starting Prices are CY 1999)

Fuel Type	UNIT	Heat Content MBtu/Unit	Delivered Price		Fuel Commodity		Transportation		Base Annual Avg. Inc. 2000-2018	Low Annual Avg. Inc. 2000-2018	High Annual Avg. Inc. 2000-2018
			$/Unit	$/mmBtu	$/Unit	$/mmBtu	$/Unit	$/mmBtu			
1.8% Resid	BBL	6.30	12.00	1.905	10.50	1.667	1.50	0.238	3.0%	2.3%	4.0%
1.0% Resid	BBL	6.30	13.00	2.063	11.50	1.825	1.50	0.238	3.0%	2.3%	4.0%
3.0% Resid	BBL	6.30	10.50	1.667	9.00	1.429	1.50	0.238	3.0%	2.3%	4.0%
#2 Distillate	BBL	5.83	16.81	2.883	15.31	2.626	1.50	0.257	3.0%	2.3%	4.0%
Natural Gas - FTS-1	EQBBL	6.30	16.40	2.603	12.41	1.970	3.99	0.633	3.0%	2.3%	4.0%
Natural Gas - FTS-2	EQBBL	6.30	19.06	3.025	12.41	1.970	6.65	1.055	2.6%	1.9%	3.6%
Petroleum Coke	Tons	28.00	11.59	0.414	4.59	0.164	7.00	0.250	2.0%	1.0%	2.3%
SJRPP Blend*	Tons	25.12	35.22	1.402	N/A	N/A	N/A	N/A	1.3%	0.3%	1.6%
Scherer 4 Coal	Tons	18.70	30.45	1.628	N/A	N/A	N/A	N/A	0.8%	0.0%	1.1%

NOTE:
Blend is 83.4 percent coal and 16.6 percent petroleum coke for 1999; 80 percent coal and 20 percent petroleum coke thereafter.

Table 2-2 Forecast of the GDP Deflator		
Year	Chained Weight	Percent Growth
1999	115.6	
2000	118.2	2.30
2001	121.0	2.30
2002	123.7	2.30
2003	126.6	2.30
2004	129.5	2.30
2005	132.5	2.30
2006	135.5	2.30
2007	138.6	2.30
2008	141.8	2.30
2009	145.1	2.30
2010	148.4	2.30
2011	151.8	2.30
2012	155.3	2.30
2013	158.9	2.30
2014	162.6	2.30
2015	166.3	2.30
2016	170.1	2.30
2017	174.0	2.30
2018	178.0	2.30

2.2 Environmental Goals

JEA continues to strive to meet or exceed environmental regulations set forth at the federal, state, and municipal levels to ensure the safety and health of all residents in and near Jacksonville and surrounding communities.

In addition, in conjunction with the solid fuel repowering of Northside Units 1 and 2, JEA established a goal to reduce environmental emissions of SO_2, NO_x, and particulates by 10 percent for the Northside Station steam units upon commercial operation of the repowered units in comparison to 1994/1995 levels. This initiative will provide a cleaner environment for the residents in conjunction with the addition of electric generation resources. Even with the increased power output and capacity factor of the repowered generating units, annual emission rates will be greatly reduced.

Actual historical emissions of Kennedy Generating Station Unit 10 are being used as offsets for permitting the simple cycle combustion turbine at this site, effectively replacing an old residual oil burning unit with a state-of-the-art, natural-gas fired combustion turbine with low sulfur diesel backup fuel.

2.3 Reliability Measures

JEA uses a fifteen percent planning margin as a criteria for providing reliable electricity to its consumers. The fifteen percent planning margin is accepted by the Florida Reliability Coordinating Council (FRCC) and is consistent with requirements in other regions of the nation. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load projections. JEA plans to maintain the fifteen percent reserve margin only for firm load obligations. Interruptible load is not considered in the fifteen percent planning reserve margin.

FUTURE SUPPLY
RESOURCE NEEDS

3.0 Future Supply Resource Needs

The future power supply resource needs for the JEA system are presented in this section. The need is based on current system supply resources, forecasts of customer energy and demand growth, transmission system needs, and future resource changes.

3.1 Existing Supply Resources

3.1.1 Electric System

3.1.1.1 Load and Energy Characteristics. JEA's load and electrical characteristics have many similarities to other Peninsular Florida utilities. The JEA's calendar year 1998 peak demand was 2,338 MW, occurring in July. The net energy for load (NEL) for 1998 was 11,470 GWH. Summer peak demand has increased at an average annual rate of 3.51 percent over the period from 1989 through 1998. Winter peak demand has increased at an average annual rate of 1.97 percent over the period from 1989 through 1998. Net energy for load has increased at an average annual rate of 3.43 percent over the period from 1989 through 1998.

3.1.1.2 Generating Capability. The generating capability of the JEA system currently consists of the Kennedy, Northside, and Southside generating plants, and joint ownership in St. Johns River Power Park and Scherer generating plants. Total net capability of the JEA generation system is 2,734 MW in the winter and 2,629 MW in the summer. Details of the existing facilities are displayed in Table 3-1.

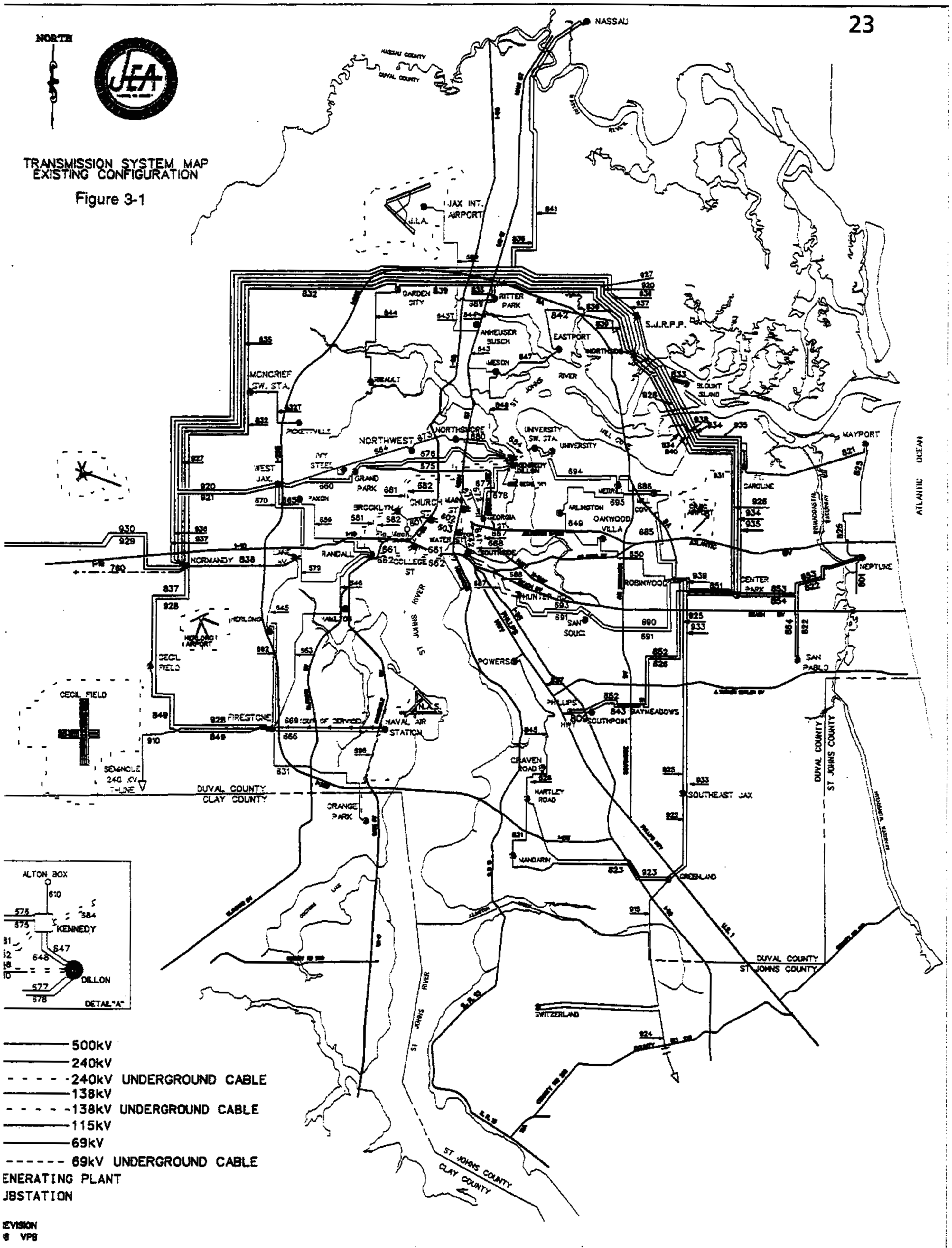
3.1.1.3 Transmission and Interconnections. The JEA transmission system consists of bulk power transmission facilities operating at 69 kV or higher. This includes all transmission lines and associated facilities where each transmission line ends at the substation's termination structure. The JEA owns 684 circuit-miles of transmission lines at five voltage levels: 69kV, 115kV, 138kV, 230kV, and 500kV. The JEA transmission system includes a 230 kV loop surrounding the JEA service territory. The existing transmission system is shown in Figure 3-1.

JEA is currently interconnected with Florida Power & Light (FP&L), Seminole Electric Cooperative (SECI), and Florida Public Utilities (FPU). Interconnections with FP&L are at 115 kV to the FP&L Baldwin Substation and 230 kV to the FP&L Sampson

Table 3-1
Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(13)	(14)		(15)
Plant Name	Unit Number	Location	Unit Type	Fuel Type Primary	Fuel Type Alt.	Fuel Transport Primary	Fuel Transport Alt.	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen Max Nameplate kW	Net MW Capability Summer	Net MW Capability Winter	Ownership	Status
Kennedy										418,200	241	286		(a)
	8	12-031	FS	HO		WA		7/1955	(b)	50,000	43	43	Utility	M
	9	12-031	FS	NG	HO	PL	WA	1/1958	(b)	50,000	43	43	Utility	M
	10	12-031	FS	NG	HO	PL	WA	12/1961	3/2000	149,600	97	97	Utility	(e)
	3-5	12-031	GT	LO		WA/TK		7/1973	(b).	168,600	144	189	Utility	
Northside										1,407,100	955	1,015		(a)
	1	12-031	FS	NG	HO	PL	WA	11/1966	(b)	297,500	262	262	Utility	
	2	12-031	FS	HO		WA		3/1972	(b)	297,500	262	262	Utility	M
	3	12-031	FS	NG	HO	PL	WA	7/1977	(b)	563,700	505	505	Utility	
	3-6	12-031	GT	LO		WA/TK		1/1975	(b)	248,400	188	248	Utility	
Southside										231,600	209	209		(a)
	4	12-031	FS	NG	HO	PL	WA	11/1958	10/2001	75,000	67	67	Utility	
	5	12-031	FS	NG	HO	PL	WA	9/1964	10/2001	156,600	142	142	Utility	
Girvin Landfill	1-4	12-301	IC	NG		PL		6/1997	(b)	3	3	3	Utility	(a)
St. Johns River Power Park										1,359,200	1,021	1,021		(c)
	1	12-301	FS	C-BIT		RR,WA		3/1987	3/2027	679,600	510	510	Joint	(c)
	2	12-301	FS	C-BIT		RR,WA		5/1988	5/2028	679,600	510	510	Joint	(c)
Scherer	4	13-207	FS	C-SUB	C-BIT	RR	RR	2/1989	2/2029	846,000	200	200	Joint	(d)
JEA System Total											2,629	2,734		(a)

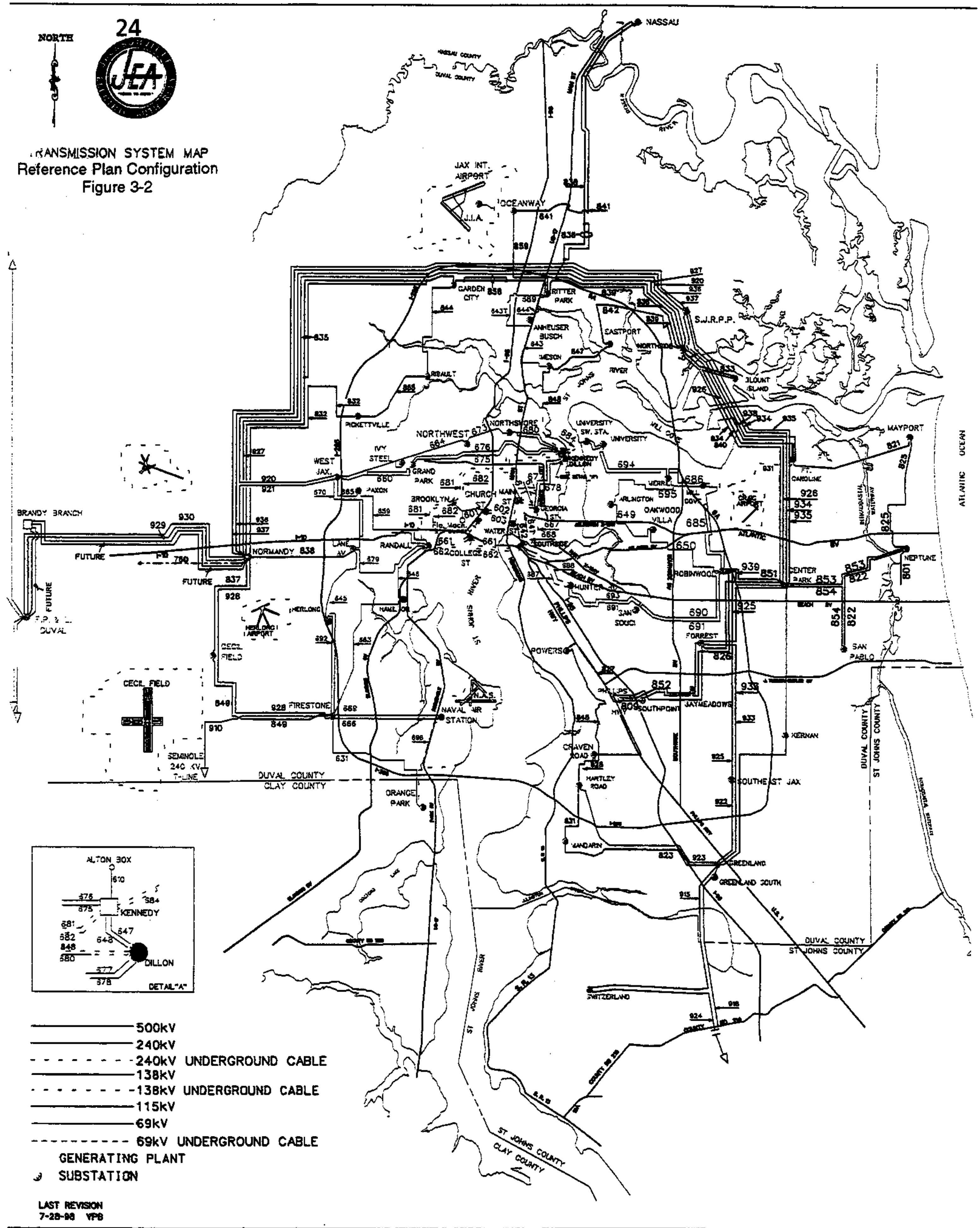
NOTE:
(a) Plant and System total net capability do not include units designated as inactive reserve (M)
(b) Life extension will continue to be an on going process as long as it is economical to do so.
(c) Net capability reflects the JEA's 80% ownership of Power Park. Nameplate is original nameplate of the unit.
(d) Nameplate and net capability reflects the JEA's 23.64% ownership in Scherer 4.
(e) Unit derated from net 129 MW and will be shutdown, not retired, March 2000.



TRANSMISSION SYSTEM MAP
EXISTING CONFIGURATION

Figure 3-1

TRANSMISSION SYSTEM MAP
Reference Plan Configuration
Figure 3-2



and Duval Substations. The interconnection to SECI is at 230 kV and at 138 kV to FPU. The JEA and FP&L jointly own two 500 kV transmission lines that are interconnected with Georgia Power Company. The JEA, FP&L, Florida Power Corporation (FPC) and the City of Tallahassee each own transmission interconnections with Georgia Power Company. JEA's entitlement over these transmission lines is 1,228 out of 3,600 MW import capability.

The JEA system is interconnected with the 500 kV transmission lines at FPL's Duval Substation. Figure 3-2 is a map of JEA's proposed transmission system for the Reference Plan.

3.1.1.4 Service Area. The JEA's electric service area covers all of Duval County and portions of Clay County, Nassau County, and St. Johns County. The JEA serves approximately 900 square miles.

3.1.2 Jointly Owned Generating Units

3.1.2.1 St. Johns River Power Park. The St. Johns River Power Park (SJRPP) is jointly owned between the JEA (80 percent) and FP&L (20 percent). The SJRPP consists of two nominal 638 MW bituminous coal fired units located north of the Northside Power Plant. Unit 1 began commercial operation in March of 1987 and Unit 2 followed in May of 1988. Both owners are entitled to 50 percent of the output of the SJRPP. Since FP&L's ownership is only 20 percent, the remaining 30 percent of capacity and energy output is reflected as a firm sale. The two units have operated efficiently since commercial operation. To reduce fuel costs and increase fuel diversity, a blend of petroleum coke with coal is currently being burned.

3.1.2.2 Scherer Unit 4. The JEA and FP&L have purchased an undivided interest in Georgia Power Company's Robert W. Scherer Unit 4. Unit 4 is a coal-fired generating unit with a net output of 846 MW located in Monroe County, Georgia. The JEA purchased 150 megawatts of Scherer Unit 4 in July 1991 and purchased an additional 50 megawatts on June 1, 1995. The power from the unit is delivered by Georgia Power Company to the jointly owned 500 kV transmission lines. (See Transmission & Interconnections)

3.1.3 Power Purchases

3.1.3.1 Unit Power Sales (UPS). Southern Company and JEA entered a unit power sales contract in which JEA purchases 200 MW of firm capacity and energy from specific Southern Company coal units through the year 2010. JEA has the unilateral option, upon three years notice, to cancel 150 MW of the UPS.

3.1.3.2 Enron. JEA entered into a purchase power agreement in 1996 with Enron Power Marketing, Inc. for firm power from October 1, 1996 through December 31, 2002. The available capacity varies monthly, ranging from 64 to 85 MW in 1997 to 69 to 92 MW in 2002. This power is delivered to JEA at the Florida/Georgia interface.

3.1.3.3 PECO. A solicitation for purchase power bids in 1995 resulted in the JEA entering into a purchase power agreement with PECO Energy Company for firm peaking capacity and energy. PECO supplied to the JEA 40 MW in 1998 and will supply 50 MW in 1999 for the months of June through September.

JEA and PECO have agreed to amend the summer 1999 agreement to include an additional 17 MW for a total of 67 MWs.

3.1.3.4 The Energy Authority. JEA entered into an agreement with The Energy Authority (TEA) to purchase 25 MW of firm capacity and energy for the term June 1999 through May 31, 2001 and 80 MW firm capacity for June - August, 1999.

JEA through TEA, is in the process of acquiring capacity to fill its 2000 needs. Commitments for 25 MW Winter 2000 and 75 MW Summer 2000 have been made and final contracts are being executed. Remaining 2000 requirements will be completed by year end. The committed capacity is included as available capacity in this study. Uncommitted capacity is not included as a resource for this study.

3.1.3.5 Cogeneration. JEA has encouraged and continues to monitor opportunities for cogeneration. Cogeneration facilities reduce the demand from the JEA system and/or provide additional capacity to the JEA system. JEA purchases power from six customer-owned qualifying facilities (QF's), as defined in the Public Utilities Regulatory Policy Act of 1978, having a total installed summer peak capacity of 50 MW and winter peak capacity of 52 MW. These QF's typically serve 41 to 42 MW of on-site load, leaving a potential of 8 to 9 MW of summer and winter capacity available for sale to JEA. JEA purchases energy from these QF's on as-available (non-firm) basis.

The following JEA customers have Qualifying Facilities located within the JEA service territory.

Name	Unit Type	In-Service Date	Net Capability[3] - MW Summer	Winter
Anheiser Busch	COG[1]	Apr-88	8	9
Baptist Hospital	COG	Oct-82	7	8
Jefferson Smurfit	COG	Apr-83	33	33
Ring Power Landfill	SPP[2]	Apr-92	1	1
St Vincents Hospital	COG	Dec-91	1	1
			50	52

1 Cogenerator
2 Small Power Producer
3 Net generating capability, not net generation sold to the JEA

3.1.4 Power Sales

3.1.4.1 Seminole Electric Cooperative (SECI). JEA returned Kennedy combustion turbine Unit 4 (CT4) to service from retirement status in March 1994. Concurrently, JEA sold to SECI priority dispatch rights for one-seventh of the aggregate CT output capacity of the JEA system. JEA's CTs include Kennedy Units 3, 4, and 5, and Northside Units 3, 4, 5, and 6. For planning purposes, the JEA and SECI assume SECI's base committed capacity is 53 MW. Full entitlement sales began January 1, 1995, and will continue through December 31, 2001. SECI may, at its sole option, extend the term through May 21, 2004.

3.1.4.2 Florida Public Utilities. JEA also furnishes power to Florida Public Utilities Company (FPU) for resale to the City of Fernandina Beach in Nassau County, north of Jacksonville. JEA is contractually committed to supply FPU until 2002. For base case planning purposes, JEA assumes that it will not serve FPU after 2002. Sales to FPU in 1998 totaled 451 GWh (3.93 percent of JEA's total system energy requirements).

3.2 Load and Energy Forecasts

The 1998 base, high, and low forecasts of electric power demand, energy consumption, and number of customers was prepared by JEA. These forecasts are based on trend analyses of historical electric load data for the JEA system and adjusted for JEA's assessment of the strength of the local economy. While impacts of retail wheeling and other results of deregulation on the loads served by JEA have not been explicitly forecasted, the high and low energy growth forecasts provide a range to bracket potential effects.

The electrical power demand forecast is based on a trend analysis of historical data and analysis of the local economy, weather-normalized to typical ambient temperatures. Table 3-2 provides a summary of the base, high, and low peak and energy forecasts for the Ten-Year Site Plan. Detailed descriptions and analysis are provided in Appendix A and Section 9.0.

The energy consumption forecast represents a trend analysis of historical data for the aggregate customer base. Sales to ultimate customers by rate class was derived by trending the historical use per customer data and multiplying by the forecast of number of customers. Historical and forecast load factors were compared as a reasonableness check of the independently developed demand and energy forecasts.

3.3 Transmission System Considerations

JEA continues to monitor and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. JEA's transmission group continually reviews needs and options for increasing the capability of the transmission system. JEA has set forth the following planning criteria for the transmission system:

- Plan to limit the loading of transmission lines and auto transformers to provide safe and reliable transmission service under normal and single contingency conditions without undue expected loss of component life.
- Plan the transmission system to withstand single contingencies without loss of customer load.
- Plan the transmission system to operate within 5 percent of nominal voltage during normal and single contingency conditions.
- Plan the transmission system so that circuit breakers can interrupt the maximum available breaker fault current.
- Plan substation relays to sense breaker failures and clear faults in sufficient time to avoid generator instability problems. The worst case fault considered in planning is a three phase fault.
- Meet the Florida Reliability Coordinating Council's (FRCC) operation guidelines.
- Meet or exceed the FRCC's reliability guidelines for transmission system interface Available Transfer Capabilities. This includes the use of single contingency criteria as well as considering the needs for operating reserve margin requirements, and capacity benefit margins.

3.4 Modification and Retirement of Generating Facilities

3.4.1 Northside Units 1 and 2

On May 21, 1997, JEA approved a plan to move forward with the repowering of Northside Units 1 and 2. The project involves the installation of new circulating fluidized bed (CFB) boilers, burning petroleum coke and coal. For planning purposes the units were modeled burning petroleum coke. The project has been identified as a Clean Coal Project by the Department of Energy which will contribute $74.733 million to the repowering of Northside Unit 2. During the first two years of operation, Unit 2 will burn coal and petroleum coke each 50 percent of the time. Four coals will be demonstrated over the two year period, with re-inspection of the plant after each test burn.

The repowering project will include the following items:

- 2 - 265 MW CFB boilers
- Limestone unloading, storage and reclaim
- Fuel unloading, storage, and reclaim system
- Ash handling and storage system
- Baghouses
- Chimney
- Polishing scrubbers
- Selective Noncatalytic Reduction (SNCR)
- Solid waste landfill
- Refurbishment of existing equipment

The repowering project will result in a plant wide (steam units only) 10 percent reduction of NO_x, SO_2, and particulate emissions and a 10 percent reduction in groundwater use, while providing 265 MW of additional electric supply capacity. The project is presently in the permitting and detailed design phase, with expected completion date of April 2002.

3.4.2 Combustion Turbines

JEA has contracted with General Electric for the supply of four frame 7FA combustion turbines. One unit will be installed at the Kennedy Generating Station and three units will be installed on property owned by JEA at the Brandy Branch site near Baldwin, FL. Each simple cycle combustion turbine will operate primarily on natural gas with #2 distillate used as a backup fuel. The summer/winter output of each combustion turbine is 149,000/185,000 kW, respectively, operating on natural gas and 158,000/191,000 kW,

Table 3-2
Summary of Electric Power Demand and Net Energy for Load

	Base Case			High Case			Low Case		
	Peak Demand - MW		Net Energy For Load	Peak Demand - MW		Net Energy For Load	Peak Demand - MW		Net Energy For Load
Year	Winter	Summer	GWH	Winter	Summer	GWH	Winter	Summer	GWH
1988	1,633	1,655	8,065	1,633	1,655	8,065	1,633	1,655	8,065
1989	1,657	1,714	8,466	1,657	1,714	8,466	1,657	1,714	8,466
1990	2,012	1,789	8,538	2,012	1,789	8,538	2,012	1,789	8,538
1991	1,725	1,756	8,835	1,725	1,756	8,835	1,725	1,756	8,835
1992	1,881	1,881	9,028	1,881	1,881	9,028	1,881	1,881	9,028
1993	1,791	1,998	9,609	1,791	1,998	9,609	1,791	1,998	9,609
1994	1,936	1,918	9,609	1,936	1,918	9,609	1,936	1,918	9,609
1995	2,190	2,067	10,326	2,190	2,067	10,326	2,190	2,067	10,326
1996	2,401	2,114	10,515	2,401	2,114	10,515	2,401	2,114	10,515
1997	1,986	2,130	10,666	1,986	2,130	10,666	1,986	2,130	10,666
1998	2,338	2,318	11,470	2,338	2,318	11,470	2,338	2,318	11,470
* 1999	2,303	2,309	11,747	2,303	2,309	11,823	2,303	2,309	11,754
2000	2,464	2,384	12,123	2,514	2,440	12,532	2,440	2,366	12,097
2001	2,548	2,461	12,505	2,656	2,579	13,221	2,501	2,425	12,399
2002	2,634	2,539	12,894	2,805	2,725	13,948	2,563	2,486	12,709
2003	2,610	2,506	12,287	2,850	2,767	14,212	2,515	2,435	12,523
2004	2,694	2,582	12,643	3,011	2,925	14,992	2,576	2,494	12,820
2005	2,781	2,659	13,016	3,182	3,092	15,828	2,638	2,554	13,136
2006	2,869	2,738	13,395	3,362	3,269	16,709	2,702	2,616	13,458
2007	2,959	2,819	13,782	3,553	3,456	17,640	2,768	2,680	13,789
2008	3,051	2,901	14,179	3,754	3,654	18,624	2,836	2,745	14,130

* Winter 1999 Actual Peak

respectively, operating on #2 distillate. The combustion turbine utilizes a dry low NOx combustion system to regulate the distribution of fuel delivered to a multi-nozzle, total premix combustor arrangement. The fuel flow distribution is calculated to maintain unit load and fuel split for optimal turbine emissions. In addition, when operating on #2 distillate, demineralized water is injected into the combustion chamber to reduce the firing temperature, which reduces the formation of NOx. The ratio of the flowrate of demineralized water to #2 distillate is approximately equal. The NOx emissions when operating on natural gas and #2 distillate will be controlled to 12 and 42 ppm, respectively.

Construction for the Kennedy unit will begin May 1999 with an expected completion date of May 2000. The construction of the Brandy Branch units will begin in late 1999 with the completion of the first two units in January 2001 and the third unit in December 2001.

3.4.3 Unit Retirements and Shutdowns. The following three JEA oil/gas steam units are reaching the end of their useful lifetimes and are scheduled for retirement or shutdown.

Unit	Commercial Operation Date	Change in Status	Planned Date
Kennedy Unit 10	1961	Shutdown	March 2000
Southside Unit 4	1958	Retirement	October 2001
Southside Unit 5	1964	Retirement	October 2001

Upon retirement or shutdown, the units will all be over 35 years of age. The units are exhibiting a history of equipment failure caused by old age. Retirement of the units will allow the opportunity to replace the capacity with newer more efficient technology that will have lower emissions. For planning purposes, JEA has established the above dates for the unit retirements. Kennedy Unit 10 is shown in a shutdown mode beginning on March 2000 as potential repowering options are studied further.

3.5 Future Resource Needs

Based on the peak demand and energy forecasts, existing supply resources and contracts, transmission considerations, and unit retirements, the JEA has evaluated future supply capacity needs for the electric system. Tables 3-3 through 3-5 display the likely need for capacity when assuming the base case, high growth, or low growth load forecasts for the JEA system for a ten year period beginning in 1999.

Table 3-3
Base Case Requirements - Summer

Year	Peak Demand Retail	Peak Demand Wholesale	Peak Demand Total	Interruptible Load	Firm Peak Demand	Reserve Requirements	System Requirements	Existing Capacity	Retirements/ Shutdowns	Required Capacity
1999	2,363	92	2,455	146	2,309	346	2,655	2,660		0
2000	2,436	98	2,534	150	2,384	358	2,742	2,514	(97)	325
2001	2,512	103	2,615	154	2,461	369	2,830	2,394		436
2002	2,589	108	2,697	158	2,539	381	2,920	2,395	(210)	735
2003	2,667	0	2,667	162	2,506	376	2,881	2,093		788
2004	2,747	0	2,747	166	2,582	387	2,969	2,140		829
2005	2,829	0	2,829	170	2,659	399	3,058	2,140		918
2006	2,912	0	2,912	174	2,738	411	3,149	2,140		1,009
2007	2,997	0	2,997	178	2,819	423	3,241	2,140		1,101
2008	3,084	0	3,084	183	2,901	435	3,336	2,140		1,196

Base Case Requirements - Winter

Year	Peak Demand Retail	Peak Demand Wholesale	Peak Demand Total	Interruptible Load	Firm Peak Demand	Reserve Requirements	System Requirements	Existing Capacity	Retirements/ Shutdowns	Required Capacity
* 1999	2,310	93	2,403	100	2,303	346	2,649	2,716		0
2000	2,468	98	2,566	102	2,464	370	2,833	2,592		241
2001	2,550	103	2,653	105	2,548	382	2,930	2,593	(97)	434
2002	2,634	108	2,742	107	2,634	395	3,030	2,473	(210)	767
2003	2,720	0	2,720	110	2,610	391	3,001	2,183		818
2004	2,807	0	2,807	113	2,694	404	3,099	2,183		916
2005	2,896	0	2,896	116	2,781	417	3,198	2,245		953
2006	2,987	0	2,987	118	2,869	430	3,299	2,245		1,054
2007	3,080	0	3,080	121	2,959	444	3,403	2,245		1,158
2008	3,175	0	3,175	124	3,051	458	3,508	2,245		1,263

* Winter 1999 Actual Peak

Table 3-4

High Case Requirements - Summer

Year	Peak Demand Retail	Peak Demand Wholesale	Peak Demand Total	Interruptible Load	Firm Peak Demand	Reserve Requirements	System Requirements	Existing Capacity	Retirements/ Shutdowns	Required Capacity
1999	2,363	92	2,455	146	2,309	346	2,655	2,660		0
2000	2,492	98	2,590	150	2,440	366	2,806	2,514	(97)	389
2001	2,629	103	2,732	154	2,579	387	2,965	2,394		571
2002	2,775	108	2,883	158	2,725	409	3,134	2,395	(210)	949
2003	2,928	0	2,928	162	2,767	415	3,181	2,093		1,088
2004	3,090	0	3,090	166	2,925	439	3,363	2,140		1,223
2005	3,262	0	3,262	170	3,092	464	3,556	2,140		1,416
2006	3,443	0	3,443	174	3,269	490	3,759	2,140		1,619
2007	3,635	0	3,635	178	3,456	518	3,974	2,140		1,834
2008	3,837	0	3,837	183	3,654	548	4,202	2,140		2,062

High Case Requirements - Winter

Year	Peak Demand Retail	Peak Demand Wholesale	Peak Demand Total	Interruptible Load	Firm Peak Demand	Reserve Requirements	System Requirements	Existing Capacity	Retirements/ Shutdowns	Required Capacity
* 1999	2,310	93	2,403	100	2,303	346	2,649	2,716		0
2000	2,518	98	2,616	102	2,514	377	2,891	2,592		299
2001	2,657	103	2,760	105	2,656	398	3,054	2,593	(97)	558
2002	2,804	108	2,912	107	2,805	421	3,226	2,473	(210)	963
2003	2,960	0	2,960	110	2,850	427	3,277	2,183		1,094
2004	3,124	0	3,124	113	3,011	452	3,463	2,183		1,280
2005	3,297	0	3,297	116	3,182	477	3,659	2,245		1,414
2006	3,480	0	3,480	118	3,362	504	3,866	2,245		1,621
2007	3,674	0	3,674	121	3,553	533	4,086	2,245		1,841
2008	3,878	0	3,878	124	3,754	563	4,317	2,245		2,072

* Winter 1999 Actual Peak

Table 3-5
Low Case Requirements - Summer

Year	Peak Demand Retail	Peak Demand Wholesale	Peak Demand Total	Interruptible Load	Firm Peak Demand	Reserve Requirements	System Requirements	Existing Capacity	Retirements/ Shutdowns	Required Capacity
1999	2,363	92	2,455	146	2,309	346	2,655	2,660		0
2000	2,418	98	2,516	150	2,366	355	2,721	2,564	(97)	254
2001	2,476	103	2,579	154	2,425	364	2,789	2,394		395
2002	2,536	108	2,644	158	2,486	373	2,859	2,395	(210)	674
2003	2,597	0	2,597	162	2,435	365	2,800	2,093		707
2004	2,659	0	2,659	166	2,494	374	2,868	2,140		728
2005	2,724	0	2,724	170	2,554	383	2,937	2,140		797
2006	2,790	0	2,790	174	2,616	392	3,008	2,140		868
2007	2,858	0	2,858	178	2,680	402	3,082	2,140		942
2008	2,928	0	2,928	183	2,745	412	3,157	2,140		1,017

Low Case Requirements - Winter

Year	Peak Demand Retail	Peak Demand Wholesale	Peak Demand Total	Interruptible Load	Firm Peak Demand	Reserve Requirements	System Requirements	Existing Capacity	Retirements/ Shutdowns	Required Capacity
* 1999	2,310	93	2,403	100	2,303	346	2,649	2,716		0
2000	2,444	98	2,542	102	2,440	366	2,806	2,592		214
2001	2,503	103	2,606	105	2,501	375	2,876	2,593	(97)	380
2002	2,563	108	2,671	107	2,563	385	2,948	2,473	(210)	685
2003	2,625	0	2,625	110	2,515	377	2,892	2,183		709
2004	2,689	0	2,689	113	2,576	386	2,962	2,183		779
2005	2,754	0	2,754	116	2,638	396	3,034	2,245		789
2006	2,821	0	2,821	118	2,702	405	3,108	2,245		863
2007	2,890	0	2,890	121	2,768	415	3,183	2,245		938
2008	2,960	0	2,960	124	2,836	425	3,261	2,245		1,016

* Winter 1999 Actual Peak

4.0 Demand-Side Management Options

The demand-side management plan for JEA is instrumental in the determination of the overall least-cost resource plan. The demand-side management plan for JEA was approved by the FPSC on December 11, 1995, and continues to be integrated with supply options to evaluate overall resource plans. The FPSC goals for JEA, programs that are in place to meet these goals, and discussion of direct load control evaluated by JEA are presented briefly in this section.

JEA's DSM plan concentrates on educating customers, local building contractors, and local building inspectors on conservation measures and improvements in home design. These programs will help improve customer satisfaction by increasing the number of valuable energy services available to JEA's customers.

4.1 Goals

Within Order No. PSC-95-0461-FOF-EG, issued on April 10, 1995, the FPSC established numeric conservation goals for JEA in accordance with Rules 25-17.0001-.005 of the Florida Administrative Code. JEA has designed its DSM plan to achieve the goals set forth by the FPSC. Table 4-1 presents the approved goals for JEA.

4.2 Current Programs

JEA's DSM Plan contains three residential customer programs and one commercial/industrial program. JEA also promotes energy savings and conservation through several other general education programs.

4.2.1 Residential Programs

The three residential customer programs include:

- Architect, contractor, and building inspector continuing education classes
- Appliance efficiency education
- Low income audits

Table 4-1 Conservation Goals Set Forth by the FPSC						
	Residential			Commercial/Industrial		
	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction
Year						
1996	270	270	92	0	0	0
1997	540	540	184	0	0	0
1998	810	810	275	0	0	0
1999	1,080	1,080	367	0	0	0
2000	1,350	1,350	459	0	0	0
2001	1,620	1,620	551	0	0	0
2002	1,890	1,890	643	0	0	0
2003	2,160	2,160	734	0	0	0
2004	2,430	2,430	826	0	0	0
2005	2,700	2,700	918	0	0	0

The contractor and building inspector continuing education classes provides education and training to contractors and building inspectors to encourage energy conservation and reduce duct leakage. The classes are continuing education courses that contractors will get credit from the Florida Construction Industry Licensing Board. This program will reduce winter and summer peak demand by 639 kW and 365 kW respectively, and net energy for load 446,586 kWh in the year 2000.

The appliance efficiency education will promote the use of high efficiency pool pumps and the reduction of the number of second freezers and refrigerators. The program has a target to reduce net energy for load by 3,180,412 kWh and peak demand 530 kW at the time of summer and winter peak in the year 2000.

The low income audits provide a method to reduce energy costs to low income households by giving free advice on items to improve efficiency in the household and the cost of each item. The number of estimated energy audits is approximately 400 per year. The program has a target to reduce net energy for load by 1,387,125 kWh and summer winter peak demand by 466 and 547 kW respectively in the year 2000.

4.2.2 Commercial/ Industrial Program

The commercial program is a lighting program that strives to promote energy savings and power quality improvements. The program loans $30.00 per fixture for retrofitting with high efficiency low harmonic electronic ballasts and bulbs. The loan will be paid over a three year period at a 5.0 percent annual interest rate through a monthly charge on the customer's electric bill. The program will reduce the typical participating customer's electric bill by approximately 7 percent a month. The program effectively allows the customer to repay the loan through the electric bill savings. While potential energy reduction is not forecasted, energy reduction is expected.

The preceding programs result in the following projections for JEA's DSM Plan presented in Table 4-2.

Table 4-2
JEA's DSM Plan

	Residential			Commercial/Industrial		
Year	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction
1996	301	270	937	0	0	0
1997	618	552	1,905	0	0	0
1998	952	844	2,913	0	0	0
1999	1,292	1,140	3,948	0	0	0
2000	1,635	1,442	5,013	0	0	0
2001	1,945	1,727	6,079	0	0	0
2002	2,261	2,018	7,174	0	0	0
2003	2,579	2,314	8,296	0	0	0
2004	2,840	2,580	9,404	0	0	0
2005	3,107	2,852	10,539	0	0	0

4.3 Program Revisions

DSM program elements are being reassessed in light of the changing competitive environment. Additional commercial and residential projects may be added in the near future and some current projects deleted. The DSM revision process allows relatively rapid changes, which may be initiated at anytime by JEA. All energy-saving and demand saving activities can be considered as candidates for the DSM program.

4.4 Direct Load Control

Direct load control was not included in JEA's DSM plan approved by the FPSC in December, 1995. JEA has reevaluated the economics of direct load control and it continues to be uneconomical for the JEA system.

5.0 Supply-Side Options

The supply-side options considered for the Ten-Year Site Plan for JEA consists of self-build options, power purchase options, and advanced and renewable technologies.

5.1 Self-Build Options

JEA considered 8 self-build options for the 1999 Ten-Year Site Plan. The resources were grouped into three categories: combustion turbines (CT), CT conversions to combined cycle units, and combined cycle units. Table 5-1 presents a brief summary of the self-build options. Each of the options were given an opportunity to be selected multiple times within the year and throughout the analysis period.

The Northside 1 & 2 Repowering and the Kennedy CT projects are committed projects selected in previous studies and were not considered as alternatives for decision making in this study.

Table 5-1
Description of Generation Alternatives

Combustion Turbine Units
New 1-168 MW Frame 7FA Combustion Turbine at Brandy Branch Burning Natural Gas or #2 Distillate
New 1-168 MW Frame 7FA Combustion Turbine at a New Site Burning Natural Gas or #2 Distillate
New 2-168 MW Frame 7FA Combustion Turbine at a New Site Burning Natural Gas or #2 Distillate
New 1-168 MW Frame 7FA Combustion Turbine at Generic Site Burning Natural Gas or #2 Distillate
Combined Cycles Unit Repowerings
Heat Recovery Steam Generator with 1-168 MW Combustion Turbine at Brandy Branch 224 MW Total.
Heat Recovery Steam Generator with 2-168 MW Combustion Turbine at Brandy Branch 453 MW Total.
New Combined Cycle Units
224 MW 1x1 GE Frame 7FA combined cycle at a new site
453 MW 2x1 GE Frame 7FA combined cycle at a new site

5.2 Firm Purchased Power

In May 1997, JEA, the Municipal Electric Authority of Georgia and the South Carolina Public Service Authority (Members) formed The Energy Authority (TEA). The primary purpose of this alliance was to create value for the members and their customers by maximizing the value of the members' generation resources while using all appropriate tools to minimize risk. TEA is a wholesale power marketing organization wholly owned by its members.

TEA provided, for this study, information for long-term capacity and energy purchases representative of the probable future market. JEA is also utilizing TEA to purchase the seasonal capacity needed for 2000.

5.3 Advanced and Renewable Technologies

JEA reviews renewable and advanced technologies on a continual basis to improve the electric system for its customers. Based on a report provided by Black & Veatch, Advanced and Renewable Technologies in 1997, the JEA divided the alternatives into two categories: alternatives that were potentially viable for JEA's system and alternatives that were not viable. Alternatives that are still under development were screened from further analysis due to the high risk and uncertainty of these resources. Alternatives that required site specific conditions that JEA currently cannot provide (i.e. geothermal) were also eliminated. A third screening analysis was conducted to eliminate high cost units. The results of the analysis are presented in a separate report.

JEA has reviewed this report for the 1999 Ten Year Site Plan, and there continue to be no alternatives that are considered cost effective, at this time.

6.0 Economic Evaluation

Evaluation of the power supply alternatives was performed using the Electric Generation Expansion Analysis System (EGEAS) modeling software. EGEAS evaluates all combinations of generating unit and purchase power alternatives to determine the combination that exhibit the lowest cumulative present worth revenue requirements while maintaining user-defined reliability criteria.

6.1 Base Case Evaluation

The base case economic evaluation was conducted using base assumptions for system load and energy, fuel price and escalation, and other future conditions as discussed in Sections 2.0 and 3.0.

The Northside 1 & 2 Repowering and the new Kennedy CT are committed projects selected and approved in previous studies and were not considered as alternatives for decision making in this study. Based on the cost and performance characteristics of the supply alternatives and power purchases, the expansion plan outlined in Table 6-1 represents the least-cost plan for the JEA under the base case scenario.

The complete plan provides a well balanced mix of resources to meet JEA's system growth. Under a fully optimized expansion plan, the basecase includes purchases, combustion turbine units (CTs), and CT projects converted to combined cycle units along with the Northside 1 & 2 repowering and Kennedy CT projects.

6.2 Sensitivity Analysis

The JEA performed several sensitivities to gauge the impact of key assumptions on the least cost plan. The sensitivities are presented in sub-sections 6.2.1 through 6.2.6. The least-cost plan over the study period is identified for each sensitivity analysis and can be found in Tables 6-2 through 6-4.

The fuel and discount rate sensitivities performed yielded an expansion plan identical to the basecase with the appropriate change in the revenue requirements.

6.2.1 Low Fuel Price Escalation

The low fuel price scenario applies the low fuel price forecast to the generation planning assumptions. With the low fuel forecast, the resource plan is identical to the basecase with a decrease in the total revenues required.

6.2.2 High Fuel Price Escalation

The high fuel price scenario applies the high fuel price forecast to the generation planning assumptions. With the high fuel forecast, the resource plan is identical to the basecase with an increase in the total revenues required.

6.2.3 High Discount Rate

The high discount rate scenario uses a rate of 5.0% or 2.7% higher than the basecase. The resource plan for this sensitivity is identical to the basecase with a decrease in the total revenues required.

Table 6-1
Basecase Plan

Year	Month / Season	Plan
1999	Summer	Purchase 125 MW
2000	Annual	Purchase 300 MW
	March	Shutdown Kennedy Unit 10
	May	Build 1-168 MW CT at Kennedy
2001	January	Build 3-168 MW CTs at Brandy Branch
	October	Retire Southside Unit 4
	October	Retire Southside Unit 5
2002	Annual	Purchase 75 MW
	April	Northside 1 CFB Repowering
	April	Northside 2 CFB Repowering
2003		
2004	January	Convert 2 CTs at Brandy Branch to Combined Cycle (558 MW Total Unit; 186 Net Additional MWs)
2005		
2006	January	Build 1-168 MW CT
2007	January	Build 1-168 MW CT
2008		

6.2.4 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth are less than the expected forecasted. The low load and energy growth requires less generation resources than the base forecast. This scenario may be representative of a deregulated utility industry or a slow economy.

Table 6-2
Low Load and Energy Plan

Year	Month / Season	Expansion Plan
1999	Summer	Purchase 125 MW
2000	Annual	Purchase 275 MW
	March	Shutdown Kennedy Unit 10
	May	Build 1-168 MW CT at Kennedy
2001	January	Build 2-168 MW CTs at Brandy Branch
	October	Retire Southside Unit 4
	October	Retire Southside Unit 5
2002	January	Build 1-168 MW CT
	April	Northside 1 CFB Repowering
	April	Northside 2 CFB Repowering
2003		
2004		
2005		
2006	January	Convert 2 Brandy Branch CTs to Combined Cycle (558 MW Total Unit; 186 Additional MWs)
2007	January	Build 1-168 MW CT
2008		

6.2.5 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth are greater than the expected forecast. The high load and energy growth requires the addition of more generation and is therefore more costly.

Table 6-3
High Load and Energy Plan

Year	Month / Season	Expansion Plan
1999	Summer	Purchase 125 MW
2000	Annual	Purchase 375 MW
	March	Shutdown Kennedy Unit 10
	May	Build 1-168 MW CT at Kennedy
2001	January	Build 3-168 MW CTs at Brandy Branch
	October	Retire Southside Unit 4
	October	Retire Southside Unit 5
2002	January	Build 1-168 MW CT
	April	Northside 1 CFB Repowering
	April	Northside 2 CFB Repowering
2003		
2004	January	Convert 2 Brandy Branch CTs to Combined Cycle (558 MW Total Unit; 186 Additional MWs)
2005	January	Build 1-168 MW CT
	January	Convert 2 CTs to Combined Cycle (558 MW Total Unit; 186 Additional MWs)
2006	January	Build 1-168 MW CT
2007	January	Build 2-168 MW CT
2008	January	Build 1-168 MW CT

6.2.6 Self-Build

Table 6-4 presents the results of a sensitivity case for self builds where purchases are not available after the year 2000.

There is no viable self build option for JEA's seasonal need for 1999 and 2000. However, JEA believes there is adequate capacity internal and external to Florida to meet its' 1999 and 2000 needs. JEA is using the resources of its marketing agent, The Energy Authority, to procure the purchases needed.

The plan presented in Table 6-4 provides the least cost self build plan for JEA while meeting JEA's strategic, economic and reliability criteria.

Table 6-4
Self Build Plan

Year	Month / Season	Expansion Plan
1999	Summer	Purchase 125 MW
2000	Annual	Purchase 300 MW
	March	Shutdown Kennedy Unit 10
	May	Build 1-168 MW CT at Kennedy
2001	January	Build 3-168 MW CTs at Brandy Branch
	October	Retire Southside Unit 4
	October	Retire Southside Unit 5
2002	January	Build 1-168 MW CT
	April	Northside 1 CFB Repowering
	April	Northside 2 CFB Repowering
2003		
2004		
2005		
2006	January	Convert 2 Brandy Branch CTs to Combined Cycle (558 MW Total Unit; 186 Additional MWs)
2007	January	Build 1-168 MW CT
2008		

7.0 Environmental and Land Use Considerations

7.1 Repowering of Northside Units 1 and 2

7.1.1 Site Description

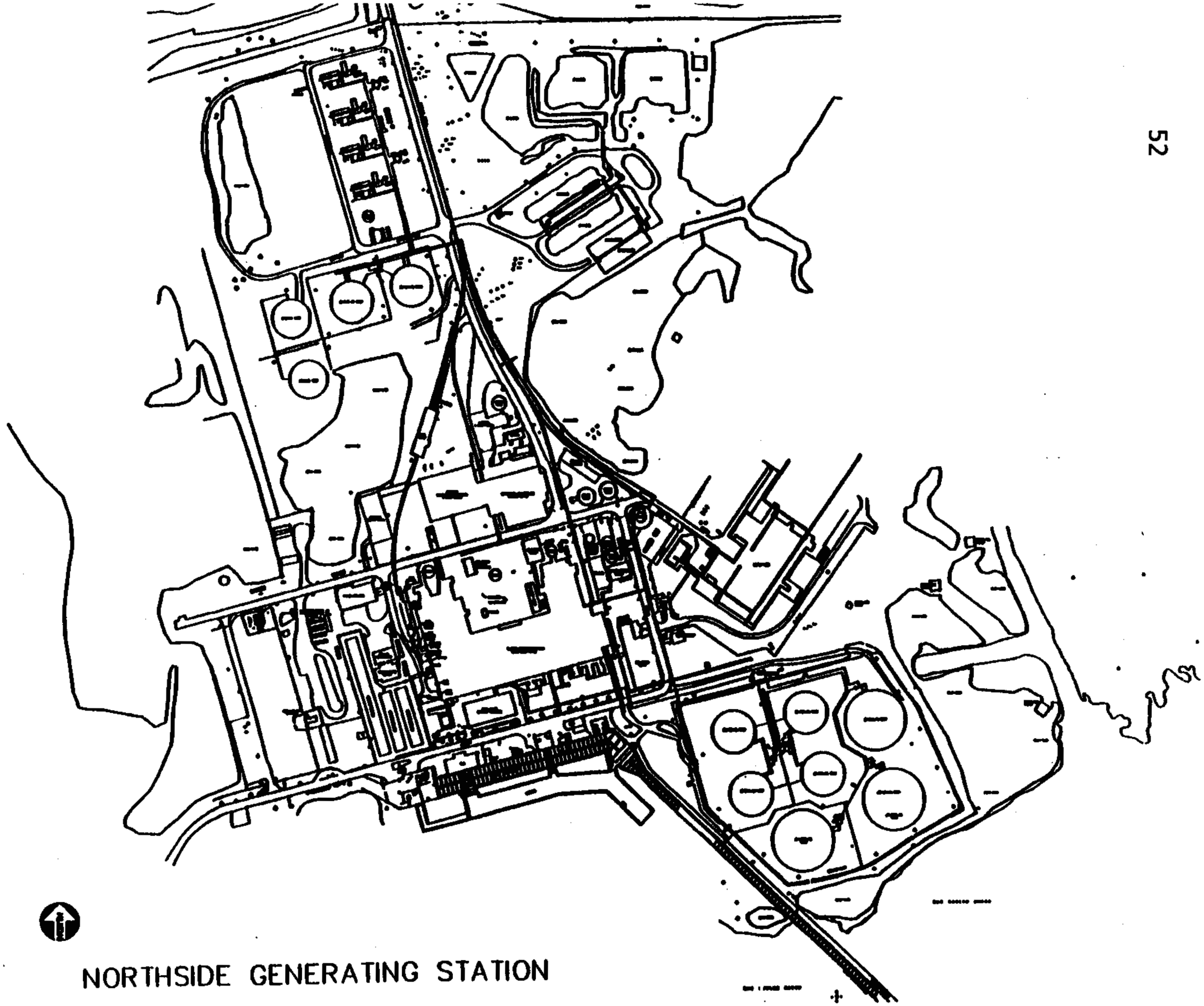
The Northside Unit 1 and 2 repowering is planned at the existing Northside Generating Station, located at 4377 Hecksher Drive in Jacksonville, Florida, just south of the St. Johns River Power Park. The Northside Generating Station contains three steam turbine and four combustion turbine units. The steam generator (boiler) for Northside Unit 2 has been dismantled. The Northside site consists of 754 total acres, of which 204 acres are currently in use. Figure 7-1 presents the Northside site arrangement. The exact location of the boilers, fuel unloading and storage facilities, waste disposal areas, and other equipment will be determined during the detailed design of the project.

7.1.2 Water Supply

JEA has committed to reduce the 1996 groundwater usage rate of 630,000 gallons per day (gpd) by at least 10 percent as part of the Northside Unit 1 and 2 repowering project. The water conservation measures implemented in the last five years at the Northside facility have reduced demands on the Floridan aquifer by nearly 50 percent. To achieve the 10 percent reduction from the baseline 1996 usage levels, which has been established as one of JEA's community commitments, the repowered facility will implement reuse and recycling as well as other water conservation measures to meet the daily groundwater usage level of 570,000 gpd.

7.1.3 Land Use

The Northside Generating Station is an existing site located in an industrial area on the north side of Duval County. It is surrounded by heavy industrial (IH), light industrial (IL), and industrial business park (IBP) zonings to the west and north and is bordered by the St. Johns River Power Park on the north, the Northside Municipal Landfill on the west. The Blount Island industrial port is located to the south. The St. Johns River and several of its tributaries border the Northside Generating Station and ancillary facilities to the west, south and east.



NORTHSIDE GENERATING STATION

7.1.4 Environmental Features

Specific environmental features of the units will be determined during detailed design. The circulating fluidized bed (CFB) units to be utilized for this project have inherently low emissions. A polishing scrubber will also be utilized to meet JEA's community commitment to reduce SO_x 10 percent from 1994/1995 baseline levels for the Northside steam units. The CFB units produce low nitrogen oxides (NO_x) due to relatively low combustion temperatures (approx. 1650°F). In addition, selective noncatalytic reduction (SNCR) will be used to further reduce NO_x emissions in order to fulfill JEA's community commitment to reduce NO_x emissions by 10 percent from 1994/1995 levels for the steam units at Northside.

7.1.5 Emissions

Emission rates will be equivalent or less than Best Available Control Technology requirements (BACT) for all criteria pollutants. In addition, JEA has a community commitment to reduce annual emissions of SO_x, NO_x, and particulate matter (PM) by 10 percent for the steam units at Northside from the historical baseline.

7.1.6 Fuel Storage

Plans are being formulated with regard to storage of the coal and pet coke fuels for the repowered facility. Existing fuel storage facilities at St. Johns River Power Park may be utilized for the project in addition to on-site covered fuel storage. BACT for control of fugitive particulate emissions will be utilized and additional controls such as paving of existing dirt roads and planting of additional vegetation will be considered.

7.1.7 Noise

Because this is an existing site, noise levels are not expected to increase significantly due to the repowering project.

7.1.8 Certification Status

Since the Northside Units 1 and 2 repowering project will not increase output of the steam turbines, the project is not required to be licensed under the Power Plant Siting Act.

7.2 New Combustion Turbines

Several combustion turbine generating units are represented within the least-cost supply plan. The planning process for the combustion turbines has just recently been started, therefore detailed analysis is not yet available. While the simple cycle combustion turbine generating unit planned for the year 2000 represents the first such generating unit in the least-cost plan, the following environmental impact summaries generically apply to all.

7.2.1 Site Description

A simple cycle combustion turbine is planned for installation at the existing Kennedy Generating Station located at 4215 Talleyrand Avenue, Jacksonville, Florida in the year 2000. Three additional simple cycle combustion turbines are planned for installation at JEA's Brandy Branch greenfield site, although the site is being designed to accomodate a fourth generator, a combustion turbine or a CT conversion to combined cycle.

All four combustion turbines are GE PG7241(FA) units with a nominal output of approximately 170 MW each. Figures 7-2 and 7-3 display the plan views of the Kennedy and Brandy Branch sites, respectively.

7.2.2 Water Supply

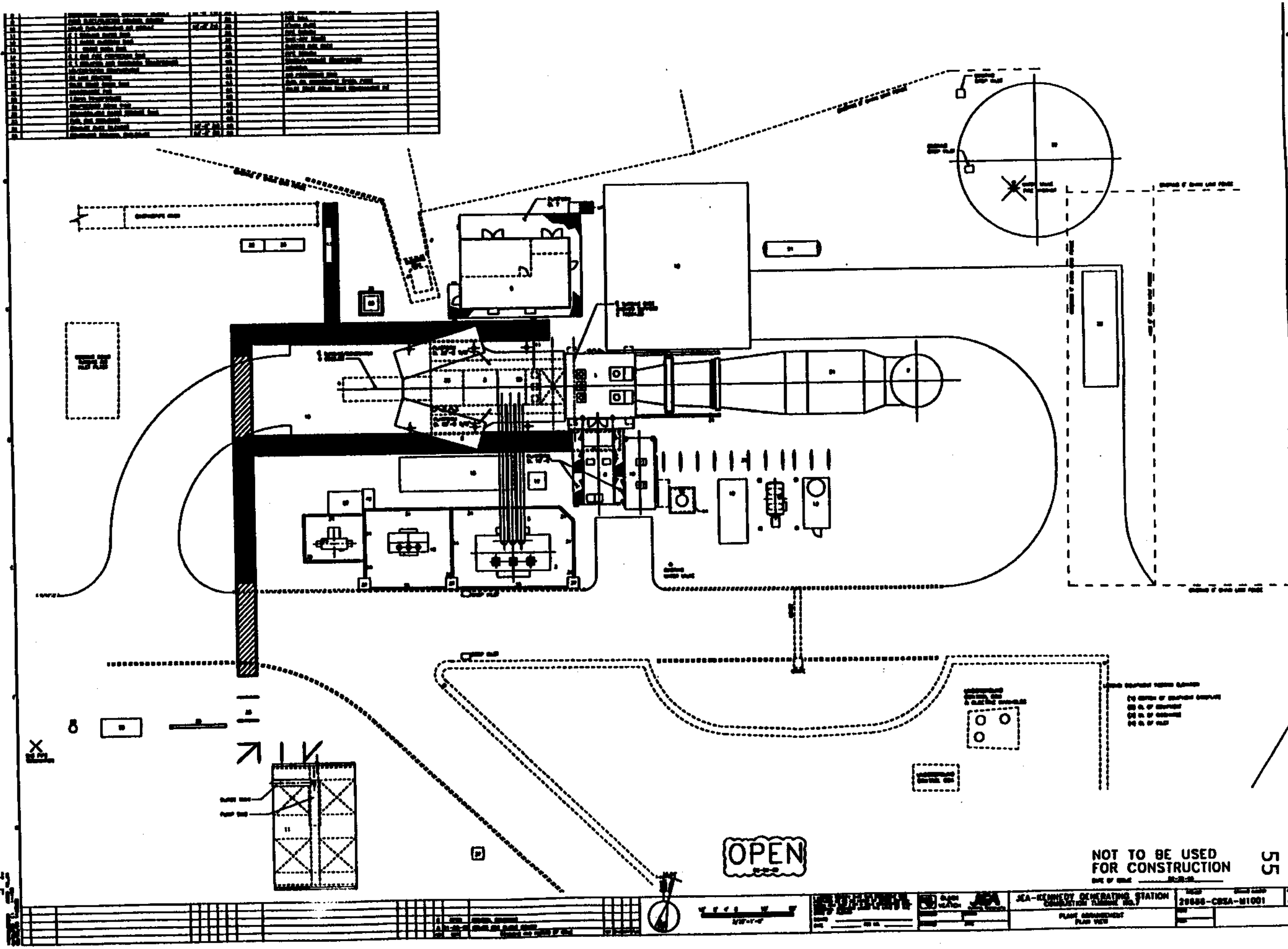
The water usage of combustion turbines is essentially limited to water injection for NO_x control and periodic unit washes. Because of the low capacity factor planned for these generating units, water usage is expected to be minimal.

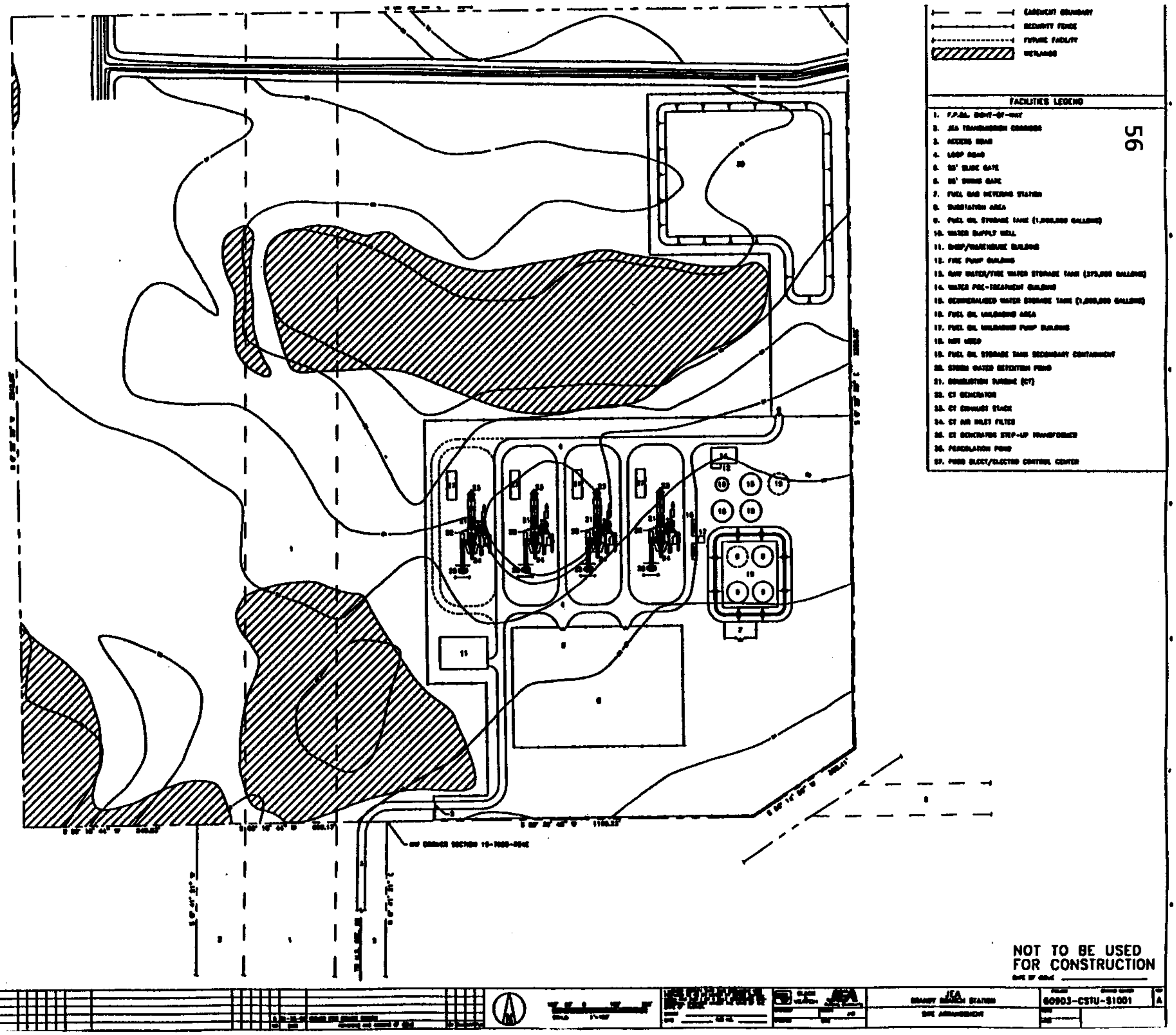
7.2.3 Land Use

The Kennedy Generating Station is located in the Talleyrand area of Jacksonville and the surrounding areas are zoned light and heavy industrial, with some commercial zoning. The Brandy Branch site is located in western Duval County near the city of Baldwin.

7.2.4 Environmental Features

The combustion turbines selected for this project are state-of-the-art machines capable of firing natural gas and distillate oil.


OPEN
NOT TO BE USED
FOR CONSTRUCTION
JEA-KENNEDY GENERATING STATION
A
55


EASEMENT BOUNDARY
SECURITY FENCE
FUTURE FACILITY
WETLANDS
FACILITIES LEGEND
1. F.P.&L. RIGHT-OF-WAY
2. JEA TRANSMISSION CORRIDOR
3. ACCESS ROAD
4. LOOP ROAD
7. FUEL GAS METERING STATION
8. SUBSTATION AREA
9. FUEL OIL STORAGE TANK (1,000,000 GALLONS)
10. WATER SUPPLY WELL
11. SHOP/WAREHOUSE BUILDING
12. FIRE PUMP BUILDING
14. WATER PRE-TREATMENT BUILDING
16. FUEL OIL UNLOADING AREA
17. FUEL OIL UNLOADING PUMP BUILDING
18. NOT USED
19. FUEL OIL STORAGE TANK SECONDARY CONTAINMENT
20. STORM WATER RETENTION POND
21. COMBUSTION TURBINE (CT)
22. CT GENERATOR
23. CT EXHAUST STACK
24. CT AIR INLET FILTER
25. CT GENERATOR STEP-UP TRANSFORMER
26. PERCOLATION POND
NOT TO BE USED
FOR CONSTRUCTION
JEA
60903-CSTU-S1001

7.2.5 *Emissions*

Emission rates will meet or exceed BACT requirements for all criteria pollutants.

7.2.6 *Fuel Storage*

Existing fuel storage facilities at the Kennedy Generating Station will be utilized for storage of distillate oil. Fuel storage facilities will be installed as necessary at the Brandy Branch site and are currently being designed.

7.2.7 *Noise*

Various sound reduction methods are being utilized for this project. The combustion turbine manufacturer has guaranteed noise limits of 85dBA for near field and 65 dBA for far field.

7.2.8 *Certification Status*

The installation of simple cycle combustion turbines is not regulated by the Power Plant Siting Act. Individual permits for each medium will be obtained for these projects in accordance with regulations.

7.3 Other Environmental and Land Use Considerations

7.3.1 *Environmental Programs*

The JEA participates in the American Public Power Association's (APPA) nationwide Tree Power program. Last year the JEA exceeded it's five-year goal of 305,000 trees planted by reaching 323,000 actual trees planted through the JEA Future Tree and Free Tree programs.

The JEA also participates in the Department of Energy (DOE) voluntary CO_2 reporting program. Projects receiving CO_2 reduction credits annually include the above mentioned programs as well as gas conversion projects at all three existing stations, landfill-gas utilization projects, free residential and non-residential energy audits, free new home construction workshops, heat rate improvements, and power factor improvements.

ANALYSIS RESULTS
AND CONCLUSIONS

8.0 Analysis Results and Conclusions

8.1 Conclusions

Applying the Basis for Decisions, Future Resource Needs, Demand-Side Options, Supply-Side Options, Economic Evaluation, and the Environmental and Land Use Considerations; JEA has determined the Reference Plan for the Ten-Year Site Plan. JEA believes it represents the least-cost plan that will meet strategic goals and provide JEA's customers with least-cost generation.

The Reference Plan is derived from the base case plan identified in Table 6-1. The Reference Plan is slightly different than the basecase because the economic evaluation applied purchased power options in block sizes for simple modeling purposes, does not reflect purchases aquired during or after the analysis, and did not capture the strategic objectives that could not be modelled.

The calculation of the actual amount of capacity required is provided in Table 8-1. The Reference Plan, outlined in Table 8-2, describes the generation additions year by year.

8.2 Recommended Reference Plan

The Reference Plan identified in Table 8-2 is submitted as JEA's 1999 Ten Year Site Plan. The plan has been studied under numerous sensitivities and represents the least-cost plan consistent with strategic objectives.

JEA through TEA is actively procurring the necessary capacity purchases to maintain a 15% reserve margin for the year 2000. TEA will also secure the remaining need that is identified in the Reference Plan.

If purchases are not an option in the out years, JEA could revert to the Self-Build Plan, section 6.2.6 and table 6-4, which required an additional CT to be installed.

Table 8-1

Base Case Requirements - Summer

Year	Peak Demand			Interruptible	Firm Peak	Reserve	System	Existing	Retirements/	Capacity	Reserve
	Retail	Wholesale	Total	Load	Demand	Requirements	Requirements	Capacity	Shutdowns	Added	Margin
1999	2,363	92	2,455	146	2,309	346	2,655	2,660		0	15%
2000	2,436	98	2,534	150	2,384	358	2,742	2,564	(97)	274	15%
2001	2,512	103	2,615	154	2,461	369	2,830	2,543		298	15%
2002	2,589	108	2,697	158	2,539	381	2,920	2,842	(210)	414	20%
2003	2,667	0	2,667	162	2,506	376	2,881	2,954		0	18%
2004	2,747	0	2,747	166	2,582	387	2,969	3,001		0	16%
2005	2,829	0	2,829	170	2,659	399	3,058	3,001		149	18%
2006	2,912	0	2,912	174	2,738	411	3,149	3,150		0	15%
2007	2,997	0	2,997	178	2,819	423	3,241	3,150		149	17%
2008	3,084	0	3,084	183	2,901	435	3,336	3,299		50	15%

Base Case Requirements - Winter

Year	Peak Demand			Interruptible	Firm Peak	Reserve	System	Existing	Retirements/	Capacity	Reserve
	Retail	Wholesale	Total	Load	Demand	Requirements	Requirements	Capacity	Shutdowns	Added	Margin
* 1999	2,310	93	2,403	100	2,303	346	2,649	2,716		0	18%
2000	2,468	98	2,566	102	2,464	370	2,833	2,592		250	15%
2001	2,550	103	2,653	105	2,548	382	2,930	2,593	(97)	558	20%
2002	2,634	108	2,742	107	2,634	395	3,030	3,031	(210)	211	15%
2003	2,720	0	2,720	110	2,610	391	3,001	2,927		265	22%
2004	2,807	0	2,807	113	2,694	404	3,099	3,192		0	18%
2005	2,896	0	2,896	116	2,781	417	3,198	3,254		0	17%
2006	2,987	0	2,987	118	2,869	430	3,299	3,254		186	20%
2007	3,080	0	3,080	121	2,959	444	3,403	3,440		0	16%
2008	3,175	0	3,175	124	3,051	458	3,508	3,440		186	19%

* Winter 1999 shows actual peak.

Table 8-2 Reference Plan		
Year	**Month/ Season**	**Expansion Plan**
1999		
2000	Winter	Purchase 250 MW
	March	Shutdown Kennedy Unit 10
	May	Build 1-168 MW CT at Kennedy
	Summer	Purchase 125 MW
2001	January	Build 2-168 MW CTs at Brandy Branch
	October	Retire Southside Unit 4
	October	Retire Southside Unit 5
	December	Build 1-168 MW CT at Brandy Branch
2002	Winter	Purchase 25 MW
	April	Northside 1 CFB Repowering
	April	Northside 2 CFB Repowering
2003		
2004		
2005	June	Convert 2 Brandy Branch CTs to Combined Cycle (558 MW Unit; 186 Additional MWs)
2006		
2007	June	Build 1-168 MW CT
2008	Summer	Purchase 50 MW

9.0 Ten Year Site Plan Schedules

The following section presents the schedules required by the Ten Year Site Plan rules for the Florida Public Service Commission.

Schedule 1
Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(13)	(14)		(15)
Plant Name	Unit Number	Location	Unit Type	Fuel Type	Fuel Transport			Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net MW Capability		Ownership	Status
				Primary	Alt.	Primary	Alt.	Mo/Yr	Mo/Yr	kW	Summer	Winter		
Kennedy										418,200	241	286		(a)
	8	12-031	FS	HO		WA		7/1955	(b)	50,000	43	43	Utility	M
	9	12-031	FS	NG	HO	PL	WA	1/1958	(b)	50,000	43	43	Utility	M
	10	12-031	FS	NG	HO	PL	WA	12/1961	3/2000	149,600	97	97	Utility	(e)
	3-5	12-031	GT	LO		WA/TK		7/1973	(b)	168,600	144	189	Utility	
Northside										1,407,100	955	1,015		(a)
	1	12-031	FS	NG	HO	PL	WA	11/1966	(b)	297,500	262	262	Utility	
	2	12-031	FS	HO		WA		3/1972	(b)	297,500	262	262	Utility	M
	3	12-031	FS	NG	HO	PL	WA	7/1977	(b)	563,700	505	505	Utility	
	3-6	12-031	GT	LO		WA/TK		1/1975	(b)	248,400	188	248	Utility	
Southside										231,600	209	209		(a)
	4	12-031	FS	NG	HO	PL	WA	11/1958	10/2001	75,000	67	67	Utility	
	5	12-031	FS	NG	HO	PL	WA	9/1964	10/2001	156,600	142	142	Utility	
Girvin Landfill	1-4	12-301	IC	NG		PL		6/1997	(b)	3	3	3	Utility	(a)
St. Johns River Power Park										1,359,200	1,021	1,021		(c)
	1	12-301	FS	C-BIT		RR,WA		3/1987	3/2027	679,600	510	510	Joint	(c)
	2	12-301	FS	C-BIT		RR,WA		5/1988	5/2028	679,600	510	510	Joint	(c)
Scherer	4	13-207	FS	C-SUB	C-BIT	RR	RR	2/1989	2/2029	846,000	200	200	Joint	(d)
JEA System Total											2,629	2,734		(a)

NOTE:
(a) Plant and System total net capability do not include units designated as inactive reserve (M)
(b) Life extension will continue to be an on going process as long as it is economical to do so.
(c) Net capability reflects the JEA's 80% ownership of Power Park. Nameplate is original nameplate of the unit.
(d) Nameplate and net capability reflects the JEA's 23.64% ownership in Scherer 4.
(e) Unit derated from net 129 MW and will be shutdown, not retired, March 2000.

Schedule 2.1
History And Forecast of Energy Consumption and Number of Customers By Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
		Rural and Residential				Commercial			Industrial		
Calendar Year	Duval County Population	Members Per Household	GWH Sales	Average No. of Customers	Average kWh/ Customer	GWH Sales	Average No. of Customers	Average kWh/ Customer	GWH Sales	Average No. of Customers	Average kWh/ Customer
1989	663,419	2.63	3,358	252,159	13,316	905	29,862	30,294	3,292	2,208	1,491,078
1990	672,971	2.61	3,629	258,075	14,060	925	29,198	31,679	3,494	2,344	1,490,751
1991	681,631	2.60	3,602	262,376	13,730	874	28,995	30,133	3,590	2,477	1,449,326
1992	693,546	2.61	3,696	266,219	13,883	873	29,144	29,945	3,660	2,596	1,409,926
1993	701,608	2.59	3,830	270,818	14,143	862	29,378	29,327	3,889	2,670	1,456,427
1994	710,592	2.55	3,909	278,682	14,027	897	29,571	30,324	4,048	2,731	1,482,265
1995	721,900	2.55	4,137	283,551	14,589	937	29,972	31,269	4,174	2,742	1,522,385
1996	731,790	2.53	4,391	288,947	15,195	937	30,162	31,079	4,353	2,975	1,463,160
1997	740,791	2.50	4,165	295,916	14,075	949	30,709	30,903	4,526	3,025	1,496,198
1998	751,978	2.49	4,643	301,883	15,380	1,035	31,297	33,070	4,835	3,094	1,562,702
1999	*	*	4,714	307,921	15,311	1,049	31,923	32,867	4,878	3,156	1,545,748
2000	*	*	4,878	314,079	15,530	1,087	32,561	33,379	5,019	3,219	1,559,217
2001	*	*	5,045	320,361	15,749	1,126	33,213	33,892	5,164	3,283	1,572,686
2002	*	*	5,218	326,768	15,968	1,166	33,877	34,405	5,312	3,349	1,586,154
2003	*	*	5,395	333,303	16,187	1,207	34,554	34,917	5,464	3,416	1,599,623
2004	*	*	5,578	339,969	16,406	1,249	35,246	35,430	5,621	3,484	1,613,092
2005	*	*	5,765	346,769	16,625	1,292	35,950	35,942	5,781	3,554	1,626,560
2006	*	*	5,958	353,704	16,844	1,337	36,669	36,455	5,945	3,625	1,640,029
2007	*	*	6,156	360,778	17,064	1,383	37,403	36,968	6,114	3,698	1,653,498
2008	*	*	6,360	367,994	17,283	1,430	38,151	37,480	6,287	3,772	1,666,967

* Duval County population not used in forecast projections

69

Schedule 2.2
History And Forecast of Energy Consumption and Number of Customers By Class

	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
Calendar Year	Street & Highway Lighting GWH	Other Sales to Ultimate Customers GWH	Total Sales to Ultimate Customers GWH	Sales For Resale GWH	Utility Use & Losses GWH	Net Energy For Load GWH	Other Customers (Average No.)	Total No.of Customers
1989	56	0	7,611	177	678	8,466	0	284,229
1990	57	0	8,105	175	258	8,538	0	289,617
1991	58	0	8,124	224	487	8,835	0	293,848
1992	59	0	8,288	309	431	9,028	0	297,959
1993	61	0	8,642	339	628	9,609	0	302,866
1994	63	0	8,917	304	388	9,609	0	310,984
1995	72	0	9,320	339	667	10,326	0	316,265
1996	70	0	9,751	363	401	10,515	0	322,084
1997	71	0	9,711	383	571	10,665	0	329,650
1998	77	0	10,590	438	442	11,470	0	336,274
1999	83	0	10,725	424	598	11,747	0	342,999
2000	90	0	11,073	442	607	12,123	0	349,859
2001	97	0	11,432	461	612	12,505	0	356,857
2002	105	0	11,800	479	614	12,894	0	363,994
2003	113	0	12,180	489	621	13,289	0	371,274
2004	123	0	12,570	517	605	13,692	0	378,699
2005	133	0	12,971	535	596	14,102	0	386,273
2006	143	0	13,383	554	582	14,519	0	393,999
2007	155	0	13,808	573	564	14,945	0	401,879
2008	167	0	14,244	591	543	15,378	0	409,916

Schedule 3
History And Forecast of Seasonal Peak Demand and Annual Net Energy For Load

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Summer Peak Demand @ Generator - MW					Annual Net Energy for Load (GWH)				Winter Peak Demand @ Generator - MW				
Calendar Year	Retail	Wholesale	Net Firm Demand	Interruptible	Total Demand	Retail	Wholesale	Total	Load Factor %	Retail	Wholesale	Net Firm Demand	Interruptible	Total Demand
1989	1,681	33	1,714	0	1,714	8,284	182	8,466	56	1,620	37	1,657	0	1,657
1990	1,749	40	1,789	0	1,789	8,358	180	8,538	48	1,939	73	2,012	0	2,012
1991	1,709	47	1,756	0	1,756	8,604	231	8,835	57	1,661	64	1,725	0	1,725
1992	1,825	56	1,881	0	1,881	8,710	318	9,028	55	1,812	69	1,881	0	1,881
1993	1,938	60	1,998	0	1,998	9,260	349	9,609	55	1,725	66	1,791	0	1,791
1994	1,865	53	1,918	0	1,918	9,296	313	9,609	57	1,866	70	1,936	0	1,936
1995	2,001	66	2,067	0	2,067	9,977	349	10,326	54	2,108	82	2,190	0	2,190
1996	2,050	64	2,114	0	2,114	10,141	374	10,515	50	2,313	88	2,401	0	2,401
1997	1,981	70	2,051	80	2,131	10,271	394	10,665	57	1,878	72	1,950	36	1,986
1998	2,146	86	2,232	106	2,338	11,019	451	11,470	56	1,842	68	1,910	65	1,975
* 1999	2,217	92	2,309	146	2,455	11,310	437	11,747	54	2,210	93	2,303	100	2,403
2000	2,286	98	2,384	150	2,534	11,668	455	12,123	54	2,366	98	2,464	102	2,566
2001	2,358	103	2,461	154	2,615	12,030	475	12,505	54	2,445	103	2,548	105	2,653
2002	2,431	108	2,539	158	2,697	12,400	493	12,894	54	2,526	108	2,634	107	2,742
2003	2,506	0	2,506	162	2,667	12,786	0	12,786	54	2,610	0	2,610	110	2,720
2004	2,582	0	2,582	166	2,747	13,159	0	13,159	53	2,695	0	2,695	113	2,807
2005	2,659	0	2,659	170	2,829	13,551	0	13,551	53	2,781	0	2,781	116	2,896
2006	2,738	0	2,738	174	2,912	13,949	0	13,949	53	2,869	0	2,869	118	2,987
2007	2,819	0	2,819	178	2,997	14,355	0	14,355	53	2,959	0	2,959	121	3,080
2008	2,901	0	2,901	183	3,084	14,770	0	14,770	53	3,051	0	3,051	124	3,175

* Winter 1999 Actual Peak.

Schedule 4
Previous Year Actual and Two Year Forecast of Peak Demand And Net Energy For Load By Month
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual 1998		Forecast 1999		Forecast 2000	
Month	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)
January	1,689	851	2,480	968	2,566	999
February	1,806	737	2,252	840	2,330	867
March	1,938	858	1,907	840	1,973	867
April	1,534	793	1,748	816	1,805	843
May	2,082	1,008	2,048	968	2,114	999
June	2,319	1,241	2,340	1,096	2,415	1,132
July	2,338	1,203	2,455	1,213	2,534	1,252
August	2,211	1,126	2,399	1,225	2,476	1,264
September	2,007	1,035	2,256	1,085	2,329	1,119
October	1,955	946	2,078	915	2,149	944
November	1,591	808	1,852	843	1,915	869
December	2,015	863	2,196	939	2,271	969
Total		11,470		11,747		12,123

Schedule 5
Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements	Type	Units	Actuals 1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Nuclear		1000 MBtu	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	3,392	3,670	3,201	3,189	3,235	2,892	2,758	2,901	2,779	2,743	2,789	2,910
(3)	Residual	Total	1000 BBL	1,639	4,985	4,802	5,040	5,402	1,383	727	718	576	435	508	551
(4)		Steam	1000 BBL	1,639	4,985	4,802	5,040	5,402	1,383	727	718	576	435	508	551
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	47	246	262	102	61	44	50	96	54	79	70	80
(9)		Steam	1000 BBL	24	36	31	31	31	28	27	28	27	27	27	28
(10)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	23	210	231	71	29	16	23	68	27	53	43	52
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 mCF	1,229	6,166	0	822	2,796	7,077	10,051	11,944	12,388	13,937	15,553	16,185
(14)		Steam *	1001 mCF	1,229	6,166	0	0	0	3,818	6,025	5,901	4,855	3,670	4,272	4,643
(15)		CC	1002 mCF	0	0	0	0	0	0	0	0	5,658	9,084	9,399	9,411
(16)		CT	1003 mCF	0	0	0	822	2,796	3,258	4,026	6,043	1,875	1,182	1,882	2,130
(17)		Diesel	1004 mCF	0	0	0	0	0	0	0	0	0	0	0	0
(18)	Pet Coke	Total	1000 Ton	300	536	614	594	624	1,880	2,155	2,168	2,141	2,152	2,159	2,177
(19)		Steam	1000 Ton	300	536	614	594	624	1,880	2,155	2,168	2,141	2,152	2,159	2,177
(20)		CC	1000 Ton	0	0	0	0	0	0	0	0	0	0	0	0
(21)		CT	1000 Ton	0	0	0	0	0	0	0	0	0	0	0	0
(22)		Diesel	1000 Ton	0	0	0	0	0	0	0	0	0	0	0	0
(23)	Other		1000 kWH	0	1,692	2,252	2,497	2,396	2,021	1,436	1,403	1,187	1,003	1,076	1,170

* Natural Gas projections for 1999 - 2001 assumes no gas burn because oil is cheaper than gas. Some gas will be burned to control emissions output.

Schedule 6.1
Energy Sources (GWH)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actuals											
	Fuel	Type	Units	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Annual Firm	Interchange	GWH	(1,643)	(2,385)	(1,506)	(1,178)	(1,338)	(1,490)	(1,260)	(1,533)	(1,634)	(1,865)	(1,832)	(1,849)
(2)	Nuclear		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWH	8,793	8,774	7,830	7,737	7,918	7,145	6,771	7,188	6,884	6,830	6,951	7,222
(4)	Residual	Total	GWH	1,469	3,044	3,004	3,159	3,383	836	440	449	342	254	302	329
(5)		Steam	GWH	1,469	3,044	3,004	3,159	3,383	836	440	449	342	254	302	329
(6)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWH	6	77	73	23	9	5	7	22	9	17	14	17
(10)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWH	6	77	73	23	9	5	7	22	9	17	14	17
(13)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	743	668	0	73	234	677	974	1,162	2,156	2,891	3,081	3,116
(15)		Steam *	GWH	743	668	0	0	0	384	609	617	483	358	425	464
(16)		CC	GWH	0	0	0	0	0	0	0	0	1,503	2,426	2,486	2,460
(17)		CT	GWH	0	0	0	73	234	293	365	545	171	107	170	193
(18)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Pet Coke	Total	GWH	647	665	1,614	1,561	1,640	5,096	5,858	5,888	5,813	5,839	5,860	5,907
(20)		Steam	GWH	647	665	1,614	1,561	1,640	5,096	5,858	5,888	5,813	5,839	5,860	5,907
(21)	Other		GWH	665	625	732	749	660	625	0	0	0	0	0	47
(22)	Net Energy for Load		GWH	10,680	11,468	11,747	12,123	12,505	12,894	12,791	13,175	13,571	13,965	14,377	14,788

* Natural Gas projections for 1999 - 2001 assumes no gas burn because oil is cheaper than gas. Some gas will be burned to control emissions output.

Schedule 6.2
Energy Sources (Percent)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actuals											
	Fuel	Type	Units	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Annual Firm Interchange		%	(15.39)	(20.80)	(12.82)	(9.72)	(10.70)	(11.55)	(9.85)	(11.64)	(12.04)	(13.36)	(12.74)	(12.51)
(2)	Nuclear		%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(3)	Coal		%	82.33	76.51	66.65	63.82	63.32	55.41	52.94	54.56	50.73	48.91	48.35	48.84
(4)	Residual	Total	%	13.75	26.54	25.57	26.05	27.05	6.48	3.44	3.41	2.52	1.82	2.10	2.22
(5)		Steam	%	13.75	26.54	25.57	26.05	27.05	6.48	3.44	3.41	2.52	1.82	2.10	2.22
(6)		CC	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(7)		CT	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(8)		Diesel	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(9)	Distillate	Total	%	0.06	0.67	0.62	0.19	0.07	0.04	0.06	0.17	0.06	0.12	0.10	0.11
(10)		Steam	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(11)		CC	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(12)		CT	%	0.06	0.67	0.62	0.19	0.07	0.04	0.06	0.17	0.06	0.12	0.10	0.11
(13)		Diesel	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(14)	Natural Gas	Total	%	6.96	5.83	0.00	0.60	1.87	5.25	7.61	8.82	15.89	20.70	21.43	21.07
(15)		Steam *	%	6.96	5.83	0.00	0.00	0.00	2.98	4.76	4.68	3.56	2.56	2.96	3.13
(16)		CC	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.07	17.37	17.29	16.63
(17)		CT	%	0.00	0.00	0.00	0.60	1.87	2.27	2.85	4.14	1.26	0.76	1.19	1.31
(18)		Diesel	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(19)	Pet Coke	Total	%	6.06	5.80	13.74	12.88	13.11	39.53	45.80	44.69	42.84	41.81	40.76	39.95
(20)		Steam	%	6.06	5.80	13.74	12.88	13.11	39.53	45.80	44.69	42.84	41.81	40.76	39.95
(21)	Other		%	6.23	5.45	6.23	6.18	5.28	4.85	0.00	0.00	0.00	0.00	0.00	0.31
(22)	Net Energy for Load		%	100	100	100	100	100	100	100	100	100	100	100	100

* Natural Gas projections for 1999 - 2001 assumes no gas burn because oil is cheaper than gas. Some gas will be burned to control emissions output.

Schedule 7
Forecast of Capacity, Demand, and Scheduled Maintenance at Time Of Peak
Summer

Year	Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance Percent	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance Percent
1999	2,630	458	430	0	2,658	2,309	349	15%	0	349	15%
2000	2,682	489	430	0	2,741	2,384	357	15%	0	357	15%
2001	2,980	291	430	0	2,841	2,461	380	15%	0	380	15%
2002	3,184	292	430	0	3,046	2,539	507	20%	0	507	20%
2003	3,184	200	430	0	2,954	2,506	449	18%	0	449	18%
2004	3,184	200	383	0	3,001	2,582	420	16%	0	420	16%
2005	3,333	200	383	0	3,150	2,659	491	18%	0	491	18%
2006	3,333	200	383	0	3,150	2,738	412	15%	0	412	15%
2007	3,482	200	383	0	3,299	2,819	481	17%	0	481	17%
2008	3,482	250	383	0	3,349	2,901	449	15%	0	449	15%

Winter

Year	Existing Capacity	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance Percent	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance Percent
* 1999	2,735	426	445	0	2,716	2,303	413	18%	0	413	18%
2000	2,735	552	445	0	2,842	2,464	379	15%	0	379	15%
2001	3,171	328	445	0	3,054	2,548	506	20%	0	506	20%
2002	3,195	280	445	0	3,031	2,634	396	15%	0	396	15%
2003	3,436	200	445	0	3,192	2,610	582	22%	0	582	22%
2004	3,374	200	383	0	3,192	2,695	497	18%	0	497	18%
2005	3,436	200	383	0	3,254	2,781	473	17%	0	473	17%
2006	3,622	200	383	0	3,440	2,869	571	20%	0	571	20%
2007	3,622	200	383	0	3,440	2,959	481	16%	0	481	16%
2008	3,808	200	383	0	3,626	3,051	575	19%	0	575	19%

* Winter 1999 shows actual peak.

Schedule 8.0
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
									Comm.			Net Capability		
	Unit		Unit	Fuel Type		Fuel Transport		Construc. Start	In-Service	Expected Retirement/	Gen Max Nameplate	Summer	Winter	
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Date	Date	Shutdown	kW	MW	MW	Status
Kennedy	10	12-031	ST	NG	FO6	PL	WA			03/01/00	149,600	102	102	M
Southside	4	12-031	ST	NG	FO6	PL	WA			10/01/01	75,000	67	67	R
Southside	5	12-031	ST	NG	FO6	PL	WA			10/01/01	156,600	142	142	R
Northside	1	12-031	ST	Pet Coke	Coal	RR	WA	09/01/99	04/01/02		269,000	269	269	C
Northside	2	12-031	ST	Pet Coke	Coal	RR	WA	09/01/99	04/01/02		269,000	269	269	RP
Kennedy	7	12-031	GT	NG	FO2	PL	TK	05/01/99	05/01/00		195,280	149	186	P
Brandy Branch	1		GT	NG	FO2	PL	TK	10/01/99	01/01/01		195,280	149	186	P
Brandy Branch	2		GT	NG	FO2	PL	TK	10/01/99	01/01/01		195,280	149	186	P
Brandy Branch	3		GT	NG	FO2	PL	TK	10/01/99	12/01/01		195,280	149	186	P
Combined Cycle *	4		CC	NG	FO2	PL	TK		06/01/05		585,840	425	504	Proposed
Combustion Turbine		New Site	GT	NG	FO2	PL	TK		06/01/07		195,280	149	186	Proposed

* Converted to Combined Cycle with two CTs at Brandy Branch.

Schedule 9.1
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Northside 1&2
(2)	Capacity:	
(3)	Summer MW	265
(4)	Winter MW	265
(5)	Technology Type:	Circulating Fluidized Bed
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	09/1999
(8)	Commercial In-Service date:	04/2002
(9)	Fuel	
(10)	Primary	Petroleum Coke
(11)	Alternate	Coal
(12)	Air Pollution Control Strategy:	CFB with Dry Scrubber, Precipitator and SNCR
(13)	Cooling Method:	Once Through Flow
(14)	Total Site Area:	200 acres
(15)	Construction Status:	Planned
(16)	Certification Status:	Not Required
(17)	Status with Federal Agencies:	Construction Permit Pending
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	7.35 percent
(20)	Forced Outage Factor (FOF):	2.5 percent
(21)	Equivalent Availability Factor (EAF):	90.15 percent
(22)	Resulting Capacity Factor (%):	90.0 percent
(23)	Average Net Operating Heat Rate (ANOHR):	9946 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30 years
(26)	Total Installed Cost (In-Service year $/kW):	
(27)	Direct Construction Cost ($/kW):	$658.0
(28)	AFUDC Amount ($/kW):	Included in direct construction cost
(29)	Escalation ($/kW):	Included in direct construction cost
(30)	Fixed O&M ($/kW-yr):	6.916
(31)	Variable O&M ($/MWh):	1.705

Schedule 9.2
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Kennedy CT 7	
(2)	Capacity:	Gas	Oil
(3)	Summer MW	149 MW	158 MW
(4)	Winter MW	186 MW	191 MW
(5)	Technology Type:	Simple Cycle Combustion Turbine	
(6)	Anticipated Construction Timing:		
(7)	Field Construction Start-date:	05/1999	
(8)	Commercial In-Service date:	05/2000	
(9)	Fuel		
(10)	Primary	Natural Gas	
(11)	Alternate	Diesel Fuel Oil	
(12)	Air Pollution Control Strategy:	Low NO_x Burners	
(13)	Cooling Method:	N/A	
(14)	Total Site Area:	5 acres	
(15)	Construction Status:	Planned	
(16)	Certfication Status:	Not Required	
(17)	Status with Federal Agencies:	AC Permit Obtained	
(18)	Projected Unit Performance Data:		
(19)	Planned Outage Factor (POF):	0.84 percent	
(20)	Forced Outage Factor (FOF):	1.5 percent	
(21)	Equivalent Availability Factor (EAF):	97.66 percent	
(22)	Resulting Capacity Factor (%):	10.0 percent	
(23)	Average Net Operating Heat Rate (ANOHR):	11,120Btu/kWh	
(24)	Projected Unit Financial Data:		
(25)	Book Life:	30 years	
(26)	Total Installed Cost (In-Service year $/kW):		
(27)	Direct Construction Cost ($/kW):	$261.0	
(28)	AFUDC Amount ($/kW):	Included in direct construction cost	
(29)	Escalation ($/kW):	Included in direct construction cost	
(30)	Fixed O&M ($/kW-yr):	2.69	
(31)	Variable O&M ($/MWh):	2.55	

Schedule 9.3
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Brandy Branch CTs 1, 2 and 3
(2)	Capacity:	Gas / Oil
(3)	Summer MW	149 MW / 158 MW
(4)	Winter MW	186 MW / 191 MW
(5)	Technology Type:	Simple Cycle Combustion Turbine
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	10/1999
(8)	Commercial In-Service date:	01/2001 Units 1 & 2 12/2001 Unit 3
(9)	Fuel	
(10)	Primary	Natural Gas
(11)	Alternate	Diesel Fuel Oil
(12)	Air Pollution Control Strategy:	Low NO_x Burners
(13)	Cooling Method:	N/A
(14)	Total Site Area:	153 acres
(15)	Construction Status:	Planned
(16)	Certfication Status:	Not Required
(17)	Status with Federal Agencies:	To Be Filed April 1999
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	0.84 percent
(20)	Forced Outage Factor (FOF):	1.5 percent
(21)	Equivalent Availability Factor (EAF):	97.66 percent
(22)	Resulting Capacity Factor (%):	5.0 percent
(23)	Average Net Operating Heat Rate (ANOHR):	11,120Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30 years
(26)	Total Installed Cost (In-Service year $/kW):	
(27)	Direct Construction Cost ($/kW):	$264.42
(28)	AFUDC Amount ($/kW):	Included in direct construction cost
(29)	Escalation ($/kW):	Included in direct construction cost
(30)	Fixed O&M ($/kW-yr):	2.83
(31)	Variable O&M ($/MWh):	2.68

Schedule 10.1 Status Report and Specifications of Proposed Directly Associated Transmission Lines Northside		
(1)	Point of Origin and Termination	Center Pk-Greenland
(2)	Number of Lines	One (1) line
(3)	Right of Way	New ROW Required
(4)	Line Length	19.3 Miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	18 months
(7)	Anticipated Capital Investment	$6,000,000
(8)	Substations	Line terminations at Center Pk and Greenland Substations
(9)	Participation with Other Utilities	None

Schedule 10.2
Status Report and Specifications of Proposed Directly Associated Transmission Lines
Brandy Branch CTs

(1)	Point of Origin and Termination	Normandy - Brandy Branch - Duval
(2)	Number of Lines	No New Lines for the First 3 CTs
(3)	Right of Way	Existing ROW
(4)	Line Length	N/A
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	9 months
(7)	Anticipated Capital Investment	$8,300,000
(8)	Substations	New Brandy Branch Substation
(9)	Participation with Other Utilities	None

Schedule 10.3 Status Report and Specifications of Proposed Directly Associated Transmission Lines Brandy Branch CC		
(1)	Point of Origin and Termination	Normandy - Brandy Branch - Duval
(2)	Number of Lines	One (1) New Line
(3)	Right of Way	Existing ROW
(4)	Line Length	N/A
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	To Be Studied At A Future Date
(7)	Anticipated Capital Investment	
(8)	Substations	
(9)	Participation with Other Utilities	None

APPENDIX A
FORECASTING METHODS AND PROCEDURES

Introduction

JEA's 1999 Ten Year Site Plan contains the results of JEA's 1998 forecast of energy production, peak demand, and number of customers. The energy production and peak demand forecasts split the difference between a constant increase in number of GWH or MW and a constant percentage growth. Adjustments were made in the resulting forecasts for the addition of Ameristeel, a large industrial customer estimated to have a 60 MW peak demand and 300 GWH per year energy consumption. The customer forecast is a time-trend of historical number of customers by rate class. This forecast does not include the potential impacts of retail wheeling and other results of deregulation as they may occur in the State of Florida over the next ten years.

JEA's forecast includes three scenarios for energy production and peak demand: a base case, a low case, and a high case. The base case is the most probable forecast. The high and low growth forecasts were developed to illustrate the differences in energy and demand requirements resulting from various growth possibilities.

Energy Production Forecast

The energy forecast represents a trend analysis of JEA's energy production excluding production for off-system sales. Weather effects were evaluated and were determined to be negligible. Analysis of JEA's historical energy production reveals a recent history of growth of 3.2%, 3.1%, and 3.7% per year for the last five, ten, and fifteen years, respectively.

Base Case

For the base case, JEA used a 3.4% per year growth rate (which is equivalent to 368 GWH per year at today's production levels) as the basis for its energy production forecast. JEA's forecast splits the difference between a constant growth rate (3.4% per year) and a constant increase in load (368 GWH per year). The impact of adding Ameristeel increased the forecast of energy production by 300 GWH beginning January 1999.

Low and High Cases

The low case forecast represents growth in energy production of a constant 2.5% per year starting in 1999, representing lower than normal economic growth for the forecast horizon. The high case forecast assumes a constant growth rate of 5.5% per year beginning in 1999, representing higher than normal economic activity at a sustained level for many years. The results of both the low and high case forecasts were adjusted for the addition of Ameristeel, which resulted in slightly higher growth rates in 1999 than those stated.

Sales of Electricity

JEA estimates its total sales to ultimate customers (which is at the customers' meter) by applying a 4.5% loss factor to its forecast of total energy production (which is measured at the generation busbar). Sales to ultimate customers by rate class was derived by trending the historical use per customer data and multiplying by the forecast of number of customers.

Peak Demand Forecast

The peak demand forecast represents a trend analysis of historical data, weather-normalized to typical temperatures. For each season, winter and summer, a separate model evaluates the effect of weather on historical peak demands and outputs weather-normalized peak demands. The weather-normalized peak demands become the basis for the trend analysis.

Weather Normalization

JEA uses minimum temperature of the day for the winter season and maximum temperature of the day for the summer season as the weather variables in the normalization methodology. For each individual year of historical data, JEA models the relationship between daily low or high temperature and daily peak demand. JEA evaluates the models at normal temperatures to estimate weather-normalized peak demands. For the purposes of this model 23 °F for the winter and 98 °F for the summer are defined to be normal weather.

Low and High Cases

The low case forecast represents growth in winter peak demand and summer peak demand of 2.5% per year throughout the forecast horizon. These assumptions are based on having lower than normal economic growth for the forecast horizon. The high case forecasts assumes a constant growth rate of 5.5% per year throughout the forecast horizon, representing higher than normal economic activity at a sustained level for many years. The results of both the low and high case forecasts were adjusted for the addition of Ameristeel, which resulted in slightly higher growth rates in 1999 than those stated.

Interruptible and Curtailable Demand

The electric power demand forecast for interruptible and curtailable (I/C) customers is based on a load profile analysis of JEA's current I/C customers. JEA has closed its I/C rate option and is not accepting applications for the rate option at this time. Currently, the JEA has signed approximately 146 MW of non-firm summer coincident peak demand and approximately 100 MW of non-firm winter peak demand.

Number of Customers

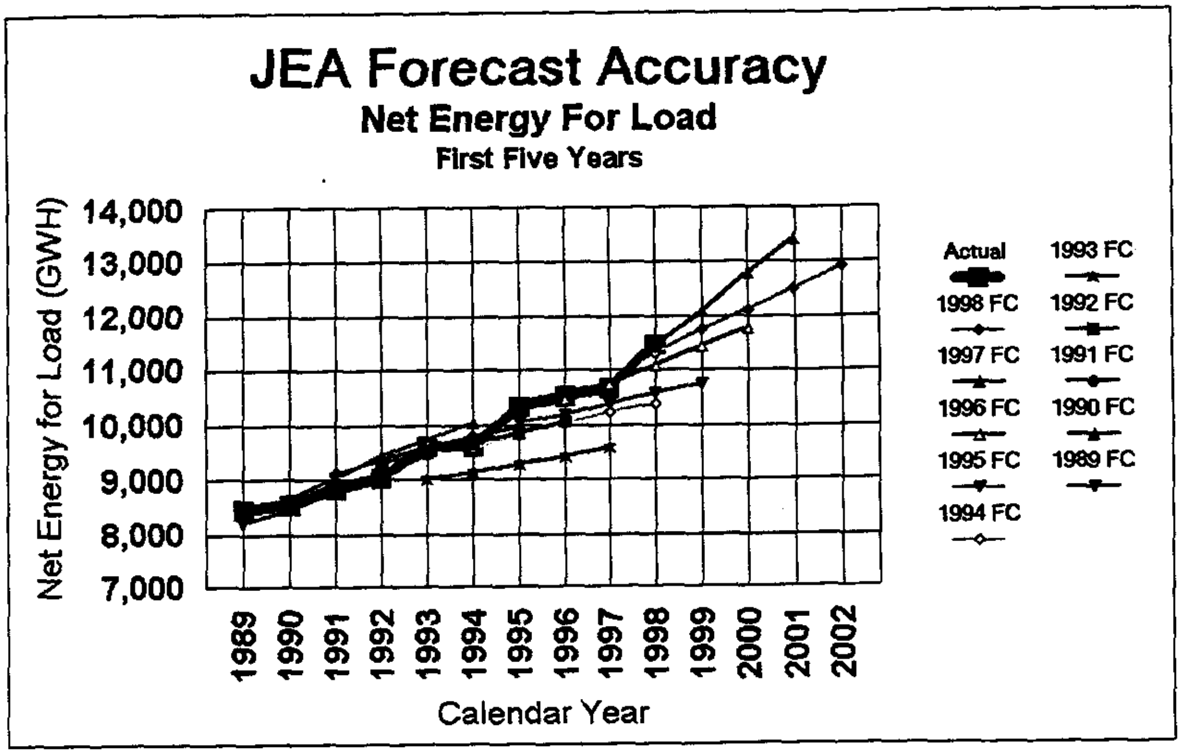
JEA's forecast of number of customers is based on an analysis of historical data on a utility total basis over the last six years. The historical data indicates that JEA's customer base is growing at a sustained rate of 2% per year. For the purposes of assessing the number of customers in any given rate class, a 2% per year growth rate is assumed beginning with the current actual totals.

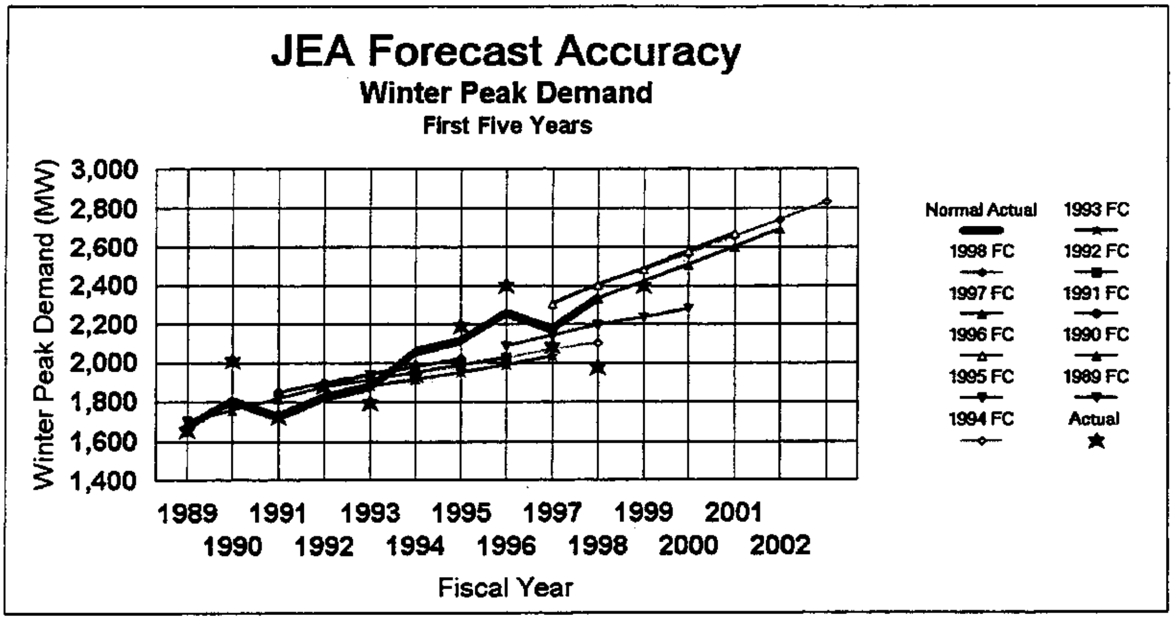
Data Sources

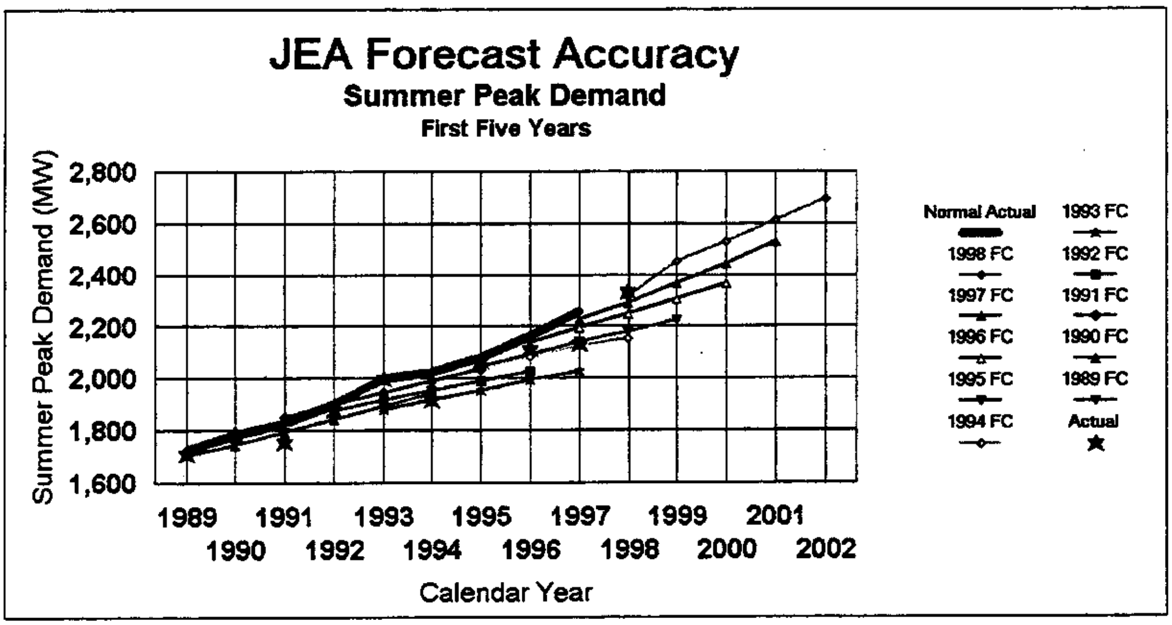
The JEA almost exclusively utilizes its own internally-generated data (number of customers, energy production, peak demand, etc.) for the purposes of producing its annual forecast of electric demand and consumption and number of customers. The only exception is JEA's use of NOAA weather data for Jacksonville, FL, which is provided to JEA by the United States Department of Commerce in a monthly report titled, "Local Climatological Data".

Forecast Accuracy

The following charts summarize an analysis of the accuracy of JEA's past ten annual energy and demand forecasts.







As these charts show, JEA's older forecasts tended to under-predict energy production and peak demand. JEA expects its current methodology will produce more accurate forecasts.